

Preparing the Electric Power Systems of North America for Transition to the Year 2000

A Status Report and Work Plan Second Quarter 1999

August 3, 1999

**Prepared for the
United States Department of Energy**

**By the
North American Electric Reliability Council**



Year 2000 Readiness Disclosure

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Executive Summary

Background

This is the fourth and final report in a series of comprehensive quarterly status reports on efforts to prepare electric power supply and delivery systems of North America for operation into the Year 2000 (Y2k). The North American Electric Reliability Council (NERC) is facilitating this Y2k readiness reporting process in response to a May 1, 1998 letter (Appendix A) from the United States Department of Energy (DOE). The letter specifically requests:

- “NERC’s assistance in assessing whether the Nation’s electricity sector is adequately prepared to address the upcoming Year 2000 computer problem.”
- That NERC “undertake the coordination of an industry process to assure a smooth transition [to the Year 2000].”
- That NERC provide DOE with written assurances that “critical systems within the Nation’s electric infrastructure have been tested, and that such systems will be ready to operate into the Year 2000.”

This report describes the readiness of electric systems of North America to operate into the Year 2000, and the systematic process used to achieve and document that readiness. Due to the interconnected nature of the electric systems in North America, NERC has expanded the scope of its facilitation efforts to include power systems in the United States and Canada, and the northern portion of the Baja California Norte, Mexico.

NERC will continue to update DOE on remaining issues identified in this report and on operational preparedness activities of the electric power industry.

Key Results of Y2k Preparations in the Electric Power Industry

NERC believes that the electric power industry will operate reliably into the Year 2000 with the resources that are Y2k Ready today. A full report on Y2k readiness status is provided in Sections 2 and 3.

Key Result 1: The Bulk Electric Systems of North America Are Ready to Operate into the Year 2000 — The bulk electric systems reporting monthly to NERC indicate more than 99% of all mission-critical facilities, systems, and components are now ready to operate into the Year 2000.

Key Result 2: Individual Organizations are Recognized by NERC to be Y2k Ready or Y2k Ready With Limited Exceptions — This report provides the first step in achieving public disclosure of the Y2k readiness status of individual electricity organizations. NERC believes that the 251 organizations listed in Appendix B are Y2k Ready or Y2k Ready With Limited Exceptions, in accordance with criteria established by NERC. All of these organizations are to be congratulated for meeting the industry target of June 30, 1999, and for

providing information to substantiate this status. Of the 251 organizations, 64 have identified to NERC specific exception items that are summarized in Appendix C. These exception items represent a fraction of a percent of total facilities being addressed within electric industry Y2k programs. NERC believes that the work schedule provided to complete these exception items in the next few months represents a prudent use of resources and does not increase risks associated with reliable electric service into the Year 2000.

Key Result 3: Progress in Local Distribution Systems Improved in the Second Quarter — The readiness of investor owned, public power, and rural cooperative distribution systems markedly improved in the past quarter. This improvement is believed to be the result of a concerted effort among the approximate 2,900 local distribution systems to increase awareness and compliance with the industry readiness target of June 30, 1999. The table below provides a brief summary indicating that 96.3% of distribution systems have been verified to be Y2k Ready. Another 3.2% of distribution systems have reported that they will be Y2k Ready before the end of the year, most of them in the third quarter. Surveys were not received from the remaining 0.5% in the most recent quarter. However, most of these entities not responding in the second quarter are believed to be Y2k Ready or to have no digital components, based on responses to surveys in previous quarters. Details on distribution systems are provided in Section 3.6 of the report and Appendices D and E.

	Investor Owned	Public Power	Cooperative	Total	%
Y2k Ready	545,962 MW	92,011 MW	69,467 MW	707,440 MW	96.3%
Not Y2k Ready	4,791 MW	8,225 MW	10,501 MW	23,517 MW	3.2%
Unknown	0 MW	2,570 MW	808 MW	3,378 MW	0.5%
Total	550,753 MW	102,806 MW	80,776 MW	734,335 MW	100%

Key Result 4: The Electric Industry Has Applied a Thorough and Systematic Approach to Addressing the Y2k Issue — The electric industry has applied a thorough and systematic process to identify, test, and fix or replace mission-critical components used to produce and deliver electricity. The process methods and results are well documented.

Key Result 5: Self-Reported Data Is Being Verified — The data used by NERC and its Y2k process partners to assess the readiness of electric systems is principally self-reported. NERC gained a greater sense of confidence in the accuracy of reported data by working closely with Y2k program managers. Of the organizations reporting to NERC, 84% of the Y2k programs have been audited. 36.7% of the programs were reviewed by both internal and external auditors; 23.4% by external auditors, and 23.9% by an internal corporate auditor.

Key Result 6: Minimal Operational Impact — Mission-critical component testing indicates that the transition through critical Y2k dates is expected to have minimal impact on electric system operations in North America. It is estimated that fewer than 3% of items that were tested during the Assessment phase had

any difficulty with Y2k date manipulations. The types of devices that did experience trouble with Y2k date manipulations exhibited mostly nuisance errors, such as incorrect date displays and date-time stamps used for data logging and reporting. In most cases, Y2k did not affect primary device functions related to keeping generators and power delivery facilities in service and electricity supplied to customers. Despite this mostly nuisance nature, many items that were found to have date issues were systematically replaced or fixed, further reducing operating risks.

Key Result 7: Contingency Plans are Y2k Ready — Although the impacts of Y2k are expected to have minimal effects on the ability to reliably operate electric power systems, the industry has taken proactive steps, under its “defense-in-depth” strategy, to prepare for possible operating contingencies. NERC and its ten Regional Reliability Councils recently completed a review of Y2k contingency plans for the more than 200 bulk electric systems of North America (control areas, transmission providers, and NERC security coordinators). More than 99% of these organizations provided plans that document well-designed strategies to prepare for operations during the transition and to respond safely and effectively to a problem. The results of the contingency planning review are provided in Section 4 of the report, with a list of participating entities in Appendix F.

Key Result 8: Y2k Efforts Are Providing Additional Benefits — The electric industry’s Y2k efforts have provided unprecedented opportunities for process improvement. Just to name a few examples, the electric industry has been able to identify and test its essential digital systems, to increase coordination of mission-critical services across intra- and intercompany boundaries, to accelerate computer system replacement projects, and to update contingency and emergency procedures. The benefits of Y2k readiness extend to everyday improvements in reliability of electricity services, not just being ready for the rollover to the Year 2000.

Key Issues

Although the electric power industry is in a good state of readiness for Y2k, there are several key issues that require continuing diligence:

Key Issue 1: Some Bulk Electric Organizations Are Not Y2k Ready — There remains a minority of electric systems that have not met the industry target of being Y2k Ready by June 30, 1999. Of the 268 entities reporting monthly to NERC, 17 (6.3%) indicated they are not yet fully Y2k Ready or Y2k Ready With Limited Exceptions. Of these late entities, the average percent completion of Remediation and Testing is 88%. Of these 17 entities, eight expect to be Y2k Ready by the end of July, three by the end of August, five by the end of September, and the last one in October. Details are provided in Section 2. Resolution of this key issue is expected by the end of the third quarter — NERC will provide a follow-up progress report to DOE.

Key Issue 2: Some Distribution Systems Are Not Y2k Ready — The progress of distribution systems in the second quarter is encouraging. However, 3.2% of distribution systems (based on MW load served) are not Y2k Ready and another 0.5% did not provide reports in the most recent quarter. Of the public power distribution systems, 8% reported not yet being Y2k Ready and another 2.5% did not participate in the surveys in the second quarter. In the cooperative area, 13% of systems are not yet Y2k Ready and another 1% did not respond in the second quarter. Some of the distribution systems in the public power and cooperative areas expect to achieve their Y2k Ready status in the fourth quarter. Tracking completion of distribution systems remains a priority for the follow-up progress report to DOE at the end of the third quarter. Details are provided in Section 3.6.

Key Issue 3: Dependency on Voice and Data Communications — This issue has been raised in the two most recent reports, but is so important that it remains a top priority for the electric industry. Operation of electric systems is highly dependent on voice and data communications, some of which are operated by external service providers. The dependence on voice and data communications directly affects real-time operations and control of electric systems and therefore continues to require attention in contingency planning and preparations. To mitigate this dependency, the following steps have been taken:

- NERC facilitated integrated Y2k tests between several electricity organizations and two major communications carriers covering facilities in three states: New York, New Jersey, and Pennsylvania. A separate report on this test activity is being prepared for publication.
- Electricity organizations have conducted face-to-face meetings with their communications service providers to share Y2k readiness information.
- NERC has scheduled two industry-wide drills that emphasize the capability to operate with loss of communications.
- Through an interindustry task force, the electric power industry has coordinated information sharing and contingency planning with other key infrastructure sectors, such as communications, natural gas, oil, and transportation.

NERC fully expects that communications services providers will be ready to operate reliably into the Year 2000.

Key Issue 4: Supply Chain Dependencies — Close analysis of the exception items in Appendix C highlights the electric industry's dependence on suppliers of critical technologies associated with power plant distributed control systems (DCS), energy management systems (EMS), supervisory control and data acquisition systems (SCADA), and communications hardware and software. Although the large majority of suppliers have been responsive to the needs of the electric industry, there remain some suppliers that are not fully cooperative or are stretched beyond their resources. The electric industry continues to seek

upgrades, testing, and certification in some of these critical areas from particular vendors. NERC will continue to report on the status of vendor support along with future updates on the Exceptions List. If necessary, NERC will report to DOE the names of individual vendor organizations requiring attention.

Continuing Industry Efforts

This report marks a transition to Phase 3 of NERC's Y2k coordination plan. Phase 1, during the summer of 1998, provided an initial assessment of Y2k readiness status and focused the industry on common objectives. Phase 2 was from September 1998 through July 1999, during which the industry concluded most of its Y2k Remediation and Testing process and NERC reported progress to DOE on a quarterly basis. Phase 3 will be completed in the remaining months of 1999 and encompasses the following activities:

1. NERC and its Regional Reliability Councils, in a cooperative partnership with several trade associations, will continue to facilitate electric industry preparations for Y2k.
2. The NERC Y2k readiness assessment process will continue to track exceptions to the June 30, 1999 readiness target and periodic updates will be provided to DOE on the status of those exceptions. NERC will closely monitor and report the progress of those organizations that are completing Y2k readiness after the June 30, 1999 target. NERC will provide a follow-up written report to DOE based on industry data through October 1999.
3. NERC and its ten Regional Reliability Councils will continue to monitor preparations for and deployment of operational and contingency plans.
4. The industry will conduct a second Y2k drill on September 8–9, 1999 to rehearse Y2k procedures, communications, and contingency response plans.
5. NERC will continue to coordinate efforts with the telecommunications industry and other critical suppliers to mitigate possible risks associated with dependencies.
6. NERC and the electric industry will support and participate in the development of the President's Y2k Information Coordination Center (ICC). The ICC will allow the monitoring of timely status information from critical infrastructure sectors during Y2k transition dates.

What Can Others Do?

Overall success of Y2k efforts in the electric industry depends on cooperation between the industry, government agencies, and customers. Provided below are suggestions as to how these stakeholders may help the process.

Federal Governments in the United States, Canada, and Mexico:

- Allow the industry to continue managing Y2k efforts. Feedback on overall goals and effectiveness of Y2k efforts should be provided through the existing industry-led program.
- Coordinate global issues related to Y2k that may have secondary effects on sustaining electricity supply in North America.
- Facilitate intersector coordination as needed to address interdependencies and assure continuity of essential services.

State, Provincial, and Local Governments

- Encourage electric utilities within the local jurisdiction to participate in the industry efforts facilitated by NERC, its Regional Reliability Councils, and the industry trade association partners. Maximize the use of the existing NERC-facilitated process and readiness assessment information. Redundant surveys and reports draw resources from the primary focus of addressing Y2k issues.
- Encourage disclosure of Y2k readiness status by jurisdictional electricity organizations, in accordance with NERC guidelines and consistent with the initial list of disclosures provided in this report. Consider the impacts of any jurisdictional electricity organizations that expect to complete the readiness of mission-critical electrical facilities after June 30, 1999.
- Facilitate interutility coordination within the jurisdiction to assure continuity of essential utility services such as electricity, water, sewage, natural gas, and telephone.
- Prior to the century day rollover, facilitate community awareness and preparedness. Foster sharing of Y2k information with the public.
- Facilitate coordination of emergency services such as police, fire, and other emergency management services. Facilitate public information processes during Y2k transition periods to ensure critical information is available in a timely manner.

Electricity Customers

Thanks to the efforts of electric utilities to prepare for Y2k and the anticipated minimal impact on electric operations, the risk of electrical outages caused by Y2k appears to be no higher than the risks we already experience. Electrical outages may occur throughout the year due to wind, ice, snow, floods, earthquakes, and other natural events. Electrical outages may also occur due to

equipment failures, traffic accidents, or a power shortage during an extremely hot or cold period. Electricity customers should review their risk exposure to everyday events that could impact electric service and historical experience with their service provider.

- Customers should identify the possible impacts of a service interruption on their business or home and initiate actions necessary to assure safety and business continuity. Power supply decisions should be based on the customer's risk exposure on a year-round basis, rather than the anticipation of any single event, such as Y2k.
- Customers should check the Y2k information provided by the local electricity provider on the Internet or through literature mailings.
- Customers with electrical demands essential to safety and public well-being, such as hospitals, emergency services, public communications, gas, water, and sewage facilities, and hazardous materials handlers should review their emergency power supply provisions and procedures, and coordinate their needs with the local electricity provider.
- Large commercial and industrial customers that would be impacted by an electrical outage should review their emergency power supply provisions and procedures. Large customers who are contacted by their energy provider should cooperate with requests for information about plans for use of electricity during Y2k transition periods.

Section 1

Background

1.1 Y2k in Electric Systems

An overview of how electric power systems work and a summary of the possible effects of Year 2000 (Y2k) on electric systems are provided in Appendix A of the January 11, 1999 report by the North American Electric Reliability Council (NERC). This report may be downloaded at <http://www.nerc.com/y2k>.

1.2 Y2k Readiness Assessment Objective

In a letter to NERC dated May 1, 1998, the United States Department of Energy (DOE) requested an initial assessment by September 1998 of the electric industry's progress in addressing the Y2k issue and assurances that electric systems are ready to operate into the Year 2000. A copy of the DOE letter is provided in Appendix A.

Recognizing the importance of continuing updates in status, the electric industry has provided written quarterly reports to DOE since September 1998. This final report is intended to satisfy the DOE request for assurances that electric systems are ready to operate into the Year 2000 by providing a comprehensive review of:

- What the electric industry is doing to address the Y2k issue and how much progress has been made through June 30, 1999.
- What the plans are to complete the preparations for Y2k.
- How the industry is preparing to deal with and minimize the impact of any contingencies on the electric system that might still occur despite best efforts to fix or replace Y2k-deficient devices.

1.3 Readiness Assessment Process

A brief overview of the readiness assessment process is provided here. A more detailed description of the process was provided in Appendix C of the January 11, 1999 NERC report to DOE (available at <http://www.nerc.com/y2k>).

NERC Y2k Readiness Assessment Process — The NERC Y2k Readiness Assessment process uses a detailed questionnaire that allows each organization to report progress across NERC-established mission-critical areas. The reporting cycle has been completed on a monthly basis since its inception in July 1998. The NERC questionnaire is targeted to the about 200 entities that own, operate, or monitor the bulk electric systems of North America.

Distribution System Process — A separate process to gather information from the approximately 2,900 distribution systems in North America is facilitated, under NERC coordination, by the American Public Power Association (APPA), the Canadian Electricity Association (CEA), the Edison Electric Institute (EEI),

and the National Rural Electric Cooperative Association (NRECA). These organizations bring the ability to closely coordinate with electric distribution entities through their existing membership channels. These four organizations have consolidated their findings into the distribution report of Section 3.6.

Nuclear Facility Process — NERC has enlisted the Nuclear Energy Institute (NEI) to provide assessment findings for nuclear facilities, which have been incorporated into Section 3.2 of the report. The coordination of NEI's Y2k program with the NERC process allows for greater efficiency and technical expertise in the nuclear area than would otherwise be available. CEA has assisted in the nuclear area by providing analysis of data from Canadian nuclear facilities.

Business Information Systems — EEI has developed the assessment report on Business Information Systems that is included in Section 3.7, based on data from the NERC assessment reports.

1.4 NERC Assessment Report Format

The NERC Y2k Readiness Assessment uses a Microsoft EXCEL™ format. This spreadsheet is available from the NERC web site at <http://www.nerc.com/y2k>. Completed responses are gathered electronically at the end of each month and compiled into an EXCEL database. The process has been automated to facilitate the aggregation of the individual reports, while maintaining the anonymity of the reporting organizations. Once submitted, the reports go through a verification and data validation process.

The final results are made public each month on the NERC Y2k web site at <http://www.nerc.com/y2k>. A list of responding entities is also provided on the NERC Y2k web site. However, NERC continues to honor a firm commitment to all reporting organizations that NERC will not connect their identities to the specific responses in the database.

The NERC Y2k Readiness Assessment spreadsheet has an initial section to identify the organization, followed by sections covering the following areas essential to sustained, reliable operations of electric systems into the Year 2000:

- General preparation (project plans, contingency plans, training, etc.)
- Nuclear power generation
- Non-nuclear power generation
- EMS/SCADA
- Telecommunications
- Substation controls and system protection (including distribution)
- Business information systems

1.5 Reporting Criteria

The criteria for reporting Y2k Ready status to NERC are defined as follows:

Y2k Ready — Y2k Ready means a system, component, or application has been determined to be suitable for continued use into the Year 2000. Note that Y2k Ready is not necessarily the same as Y2k Compliant, which requires fully correct date manipulations. The definition of Y2k Ready requires that the primary function(s) of the system, component, or application will continue to be provided reliably into the Year 2000. Although fixing or replacing a deficient system, component, or application to make it Y2k Compliant is one common solution, achieving Y2k Ready status may also be accomplished through remediation. Remediation may include, for example, a software patch to display a correct date to an operator. Remediation could also be procedural, such as providing a highly reliable alternative that allows continuation of the primary function of the system, component, or application. Being Y2k Ready requires verification that each function necessary to reliably produce and deliver electricity is very likely to:

1. Not be impaired by a Y2k failure;
2. Continue performing satisfactorily into the Year 2000; and
3. Be sustainable into the Year 2000.

Mission Critical — Mission critical describes a system, component, or application whose misoperation could directly contribute toward the loss of a 50 MW or larger generating resource, the loss of a transmission facility, or interruption of system load. Another concept for determining which items are mission critical includes those that impact the ability to keep customer lights on or impact the safety of the public or employees. The NERC report template lists component categories that should be considered mission critical.

Reasonable Exceptions — The Exception List is intended to capture mission-critical items that will be completed after June 30, 1999. Reasonable exceptions are those that do not pose a measurable risk to reliable electric operations into the Year 2000. Factors that are considered in evaluating whether exceptions are reasonable include:

- Number of facilities within an organization
- Percent of system production or delivery capacity for that organization
- Expected completion date(s)
- Importance of the facilities to the electricity production and delivery chain
- Steps taken to mitigate risks (e.g. the component has been tested offline and is Y2k Ready at the component level, but will be installed and final testing conducted during a fall 1999 outage)

Section 2

Overview of Y2k Readiness Second Quarter 1999

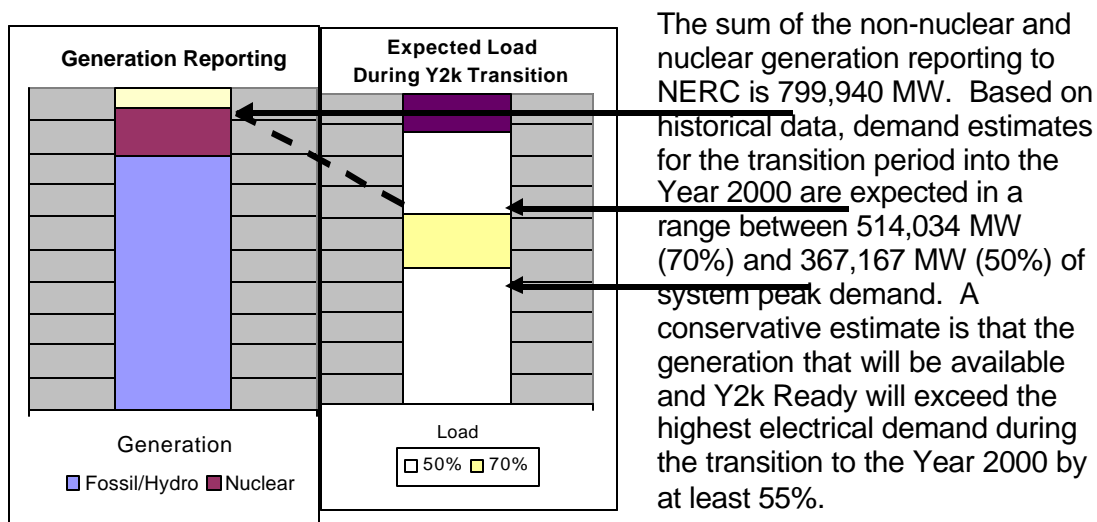
This section provides an overview of the Y2k readiness status of electric systems in North America, based on data provided through June 30, 1999. Supporting data are available for electronic download from the NERC Y2k web site at <http://www.nerc.com/y2k>.

2.1 Participation Levels

About 99% of the 3,088 electricity supply and delivery organizations in North America have participated in the NERC Y2k readiness assessment process to date. Lists of all participating organizations are available at the NERC Y2k web site at <http://www.nerc.com/y2k>.

Reports in the second quarter were received from entities representing:

- More than 717,018¹ MW (97.6%) of system peak demand out of a total estimated system peak demand for North America of 734,335² MW.
- More than 673,284 MW (92.9%) of non-nuclear generating capacity out of 724,741 MW total non-nuclear capacity estimated for North America.
- 100% of operational nuclear reactors representing 111,046 MW in the United States and 15,610 MW in Canada, reporting through NEI and CEA.



¹ This number understates the demand reported, because it is based only on NERC data. With data provided by APPA, NRECA, and CEA, the demand covered is projected to be nearly 100%.

² The estimated peak demand is based on an assumption of a 94% coincidence factor applied to the sum of the Regional peaks provided in the NERC Reliability Assessment report.

2.2 Assessment of Project Planning and Management Involvement

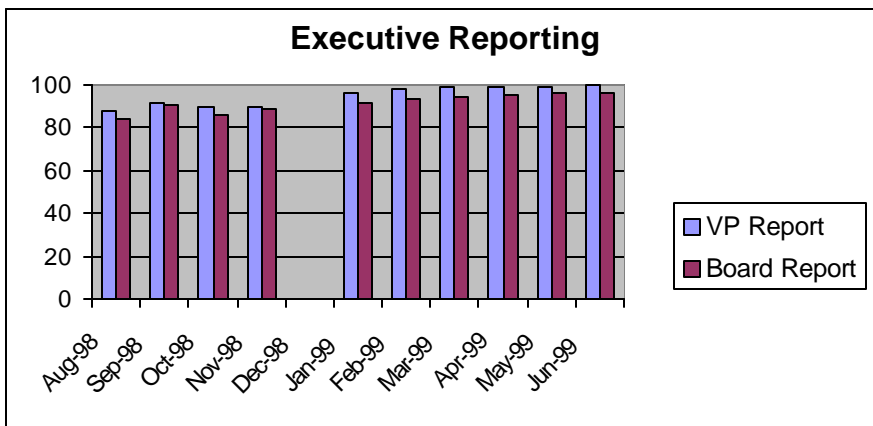
This first readiness assessment section reviews project plans and controls and management involvement. This section refers to data from the NERC assessments and therefore is limited to bulk electric systems, independent power producers (IPPs), and some of the larger distribution entities. Results from the remaining distribution systems are addressed in Section 3.6.

Executive Involvement in Y2k

Findings:

100% of reporting entities indicate the Y2k program reports to a vice president or higher or its equivalent.

97% of reporting entities indicate the board of directors or governing body of the organization receives at least quarterly briefings on the Y2k program.



Analysis:

Executive involvement has been strong throughout the NERC facilitation process and continued to improve in the most recent quarter. Every entity reporting to NERC indicates, as of June 30, 1999, that the Y2k program is the direct responsibility of a vice president or higher or its equivalent.

97% percent of reporting entities indicate the Y2k program status is reviewed by the board of directors or its equivalent on a quarterly basis. Of the 3% of organizations not reporting quarterly to a board of directors, three are Generation and Transmission (G&T) cooperatives, three are municipalities, and one is an independent power producer (IPP). Each feels it does not have the equivalent of a board of directors or that the board is not available on a quarterly basis.

Recommendations:

Executive oversight and commitment is essential to Y2k project success. The risk potential for shareholders, customers, neighboring electric systems, and dependent industries warrants that Y2k program accountability should remain at the executive level for the remainder of the Y2k process. Therefore:

1. The Y2k program at each electric supply or delivery organization should be a direct responsibility of a corporate vice president or higher (or equivalent for organizations other than corporations). This individual should be accountable for the overall success of the Y2k program.
2. The board of directors or equivalent governing body of each organization should receive at least quarterly updates of the Y2k program status.

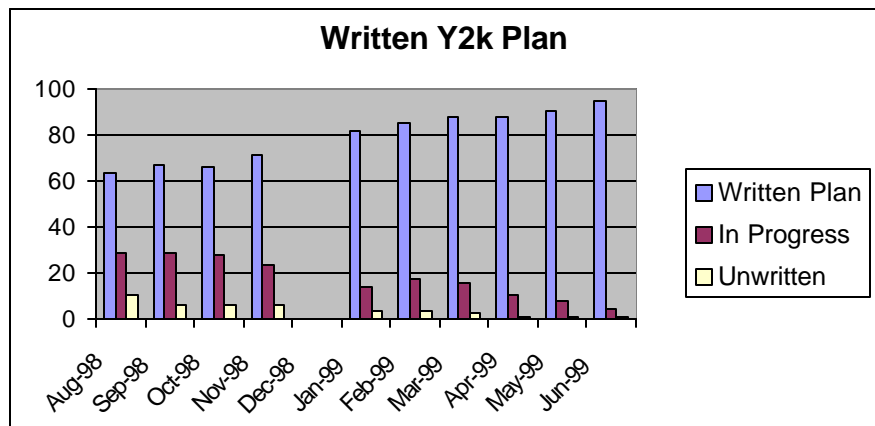
Use of a Written Y2k Plan

Findings:

94% of entities reporting indicate they have developed a written plan for the management of their Y2k projects.

5% indicate a written plan exists but is a work in progress.

1% indicate they expect to use an unwritten plan or no plan.



Analysis:

Use of written plans has continued to improve throughout the NERC-facilitated process. These plans document responsibilities, project controls, schedules, testing procedures, reporting measures, and other management tools to assure a thorough and systematic process for addressing Y2k.

Of the three organizations reporting use of unwritten plans or no plans, one is an IPP and two are distribution-only systems. Two are already Y2k Ready and the third expects to be Y2k Ready by September 30, 1999.

Recommendations:

1. The Y2k program at each electric supply or delivery organization should continue to be guided by a written plan.
2. A Y2k program plan is a dynamic document that should be continuously adapted to meet evolving requirements.

2.3 Overall Progress Compared to Y2k Milestones

Y2k progress is measured by NERC as a percent of work completed in several key phases. A percent of work completed is used in lieu of counting devices or systems completed. This approach avoids over or under statement of the work remaining, because some devices or systems can be tested and remediated very easily and others require extensive resources and time.

NERC has adopted the use of three phases: Inventory, Assessment, and Remediation and Testing. NERC has deliberately avoided placing a strict definition on these three phases to prevent conflicts with previously existing internal project definitions.

These terms are commonly accepted in the industry and represent a reasonable division of the Y2k technical work. The division of work into these phases, however, is approximate and may require a certain amount of translation from internally defined project measures within each organization. Remediation and Testing is intended to include repair or replacement of Y2k-deficient systems or components.

It should be noted that these NERC-defined work phases do not necessarily flow sequentially. They will often be completed in parallel and there may be a need to iterate between the phases. For example, some devices may require testing to complete the initial assessment of Y2k susceptibility. After repair, the device may be tested again.

The NERC progress assessment is focused on mission-critical systems associated with the reliable and sustained production, transmission, and distribution of electricity into the Year 2000. This approach is consistent with NERC's mission of facilitating the reliability of electric systems in North America.

There is a section in the NERC report for business systems. However, the focus there is on mission-critical systems needed to assure continuity of essential services.

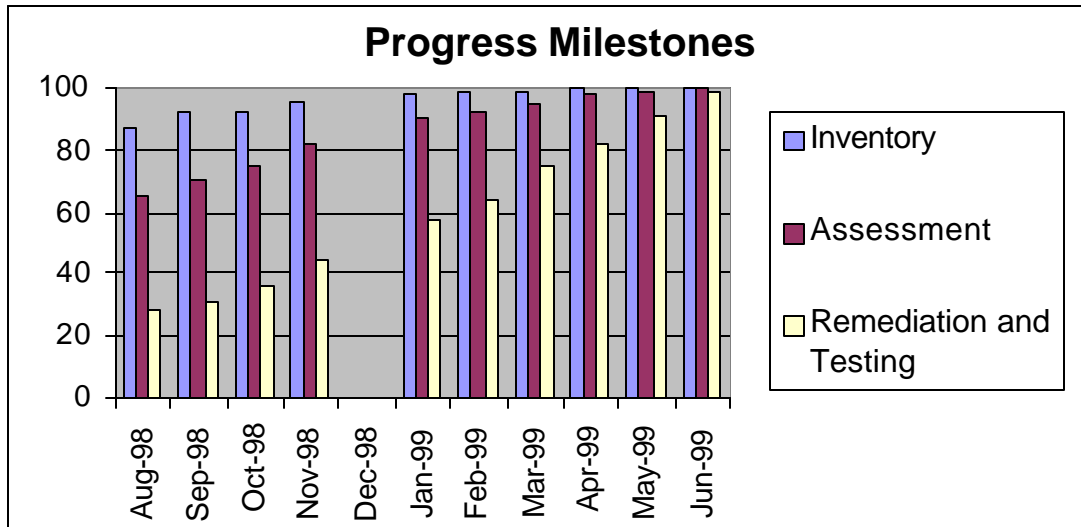
Although additional, nonessential functions may be voluntarily reported on the NERC report, ultimately these functions are the responsibility of each organization to track and complete to the satisfaction of customers, regulators, shareholders, and other stakeholders.

Findings:

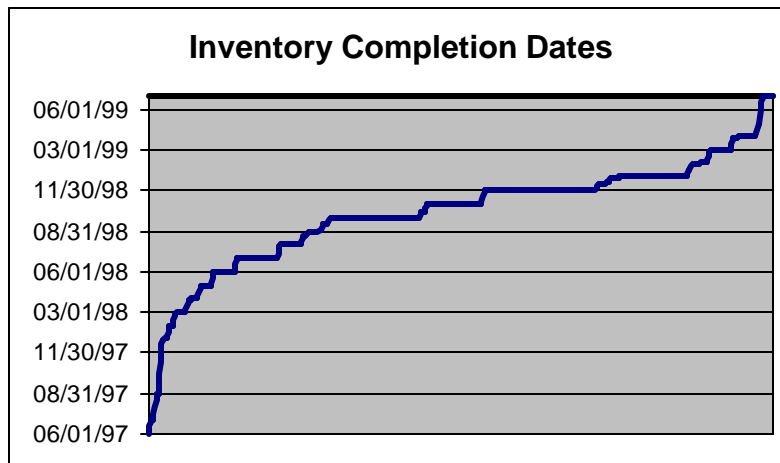
Averages of the reporting organizations for the second quarter of 1999 (as of June 30, 1999) indicate the following overall progress and average completion dates for mission-critical electrical systems:

Y2k Program Phase	Average Percent Complete June 30, 1999	Average Completion Date
Inventory	100%	October 1998
Assessment	100%	January 1999
Remediation/Testing	99%	June 1999

The monthly progress (% of effort completed) for each of the three phases is shown in the graph below.

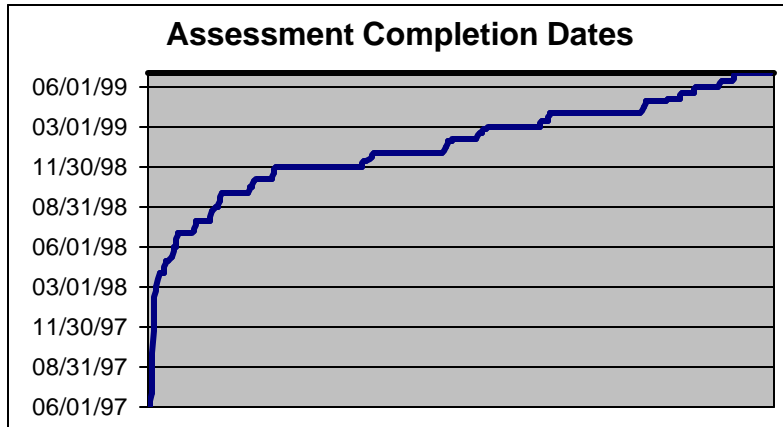


A more detailed analysis is provided below for each of the three work phases, beginning first with the Inventory phase. 100% of all organizations reporting to NERC have completed the initial Inventory. The graphic below represents the completion dates of the Inventory phase for the reporting entities. The last five organizations completed the Inventory on June 30, 1999. Typically, these later organizations were holding the Inventory process open until near the end of the testing program in case additional items were found, although the NERC reporting process was intended to capture initial Inventory efforts.

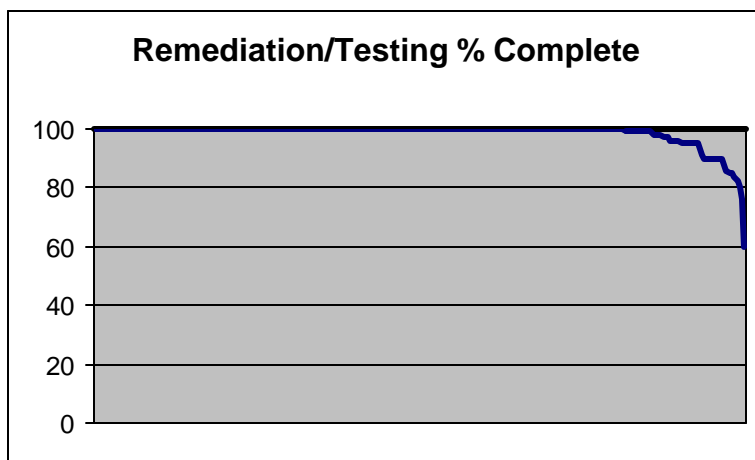


This graph and similar ones that follow have on the horizontal axis the numbers one through 268, representing each entity reporting through the NERC process in June 1999. The responses were sorted by magnitude for viewing and analysis.

A similar curve below shows that all entities reporting to NERC have completed the Assessment phase. Assessment requires an initial review of whether the device or system may be susceptible to Y2k anomalies and should be further tested, repaired, or replaced. It does not require full completion of testing and remediation. The last five organizations reported completing the Assessment phase on July 1, 1999



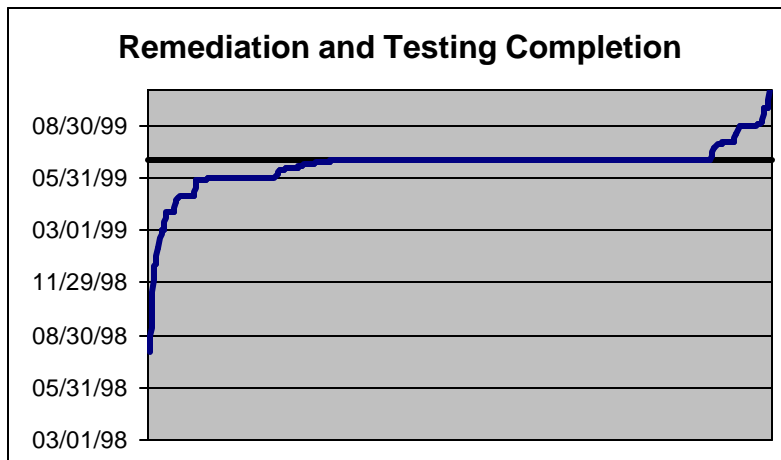
The industry target was to complete Remediation and Testing for all mission-critical electrical facilities by June 30, 1999. 251 organizations (93.6%) have completed Remediation and Testing fully or with a limited number of exceptions (see a discussion of exceptions in the next section). There are 17 organizations reporting to NERC that they have not completed the Remediation and Testing phase. These 17 programs are on average 88% complete, with the lowest level of completion being 60%. This first graph below shows completion of Remediation and Testing as a percent of effort by each organization. The small area above and to the right of the curve represents work remaining. The large area below and to the left of the curve represents work completed in Remediation and Testing.



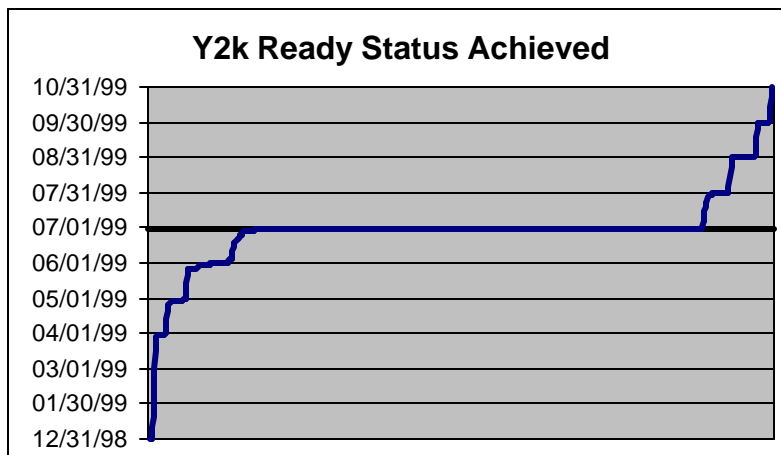
The table below summarizes the makeup of the entities that have yet to complete the Remediation and Testing phase.

	Small (<500 MW)	Mid-sized (500-2,000 MW)	Large (>2,000 MW)	Total
Investor Owned		1	1	2
Public Power	3	4	2	9
G&T Cooperative	1			1
IPP	3	2		5
Total	7	7	3	17

The second graph below shows the completion dates for Remediation and Testing. The dark line indicates a target of June 30, 1999. Of the 17 entities that are not yet complete, eight plan to be done with Remediation and Testing by the end of July, another three by the end of August, five more by the end of September, and the last one in October.



The final graph below shows the Y2k Ready dates for the entities reporting to NERC. The breakdown is similar to that above for the Remediation and Testing phase. The latest expected Y2k Ready date for the entities reporting to NERC is October 31, 1999.



Recommendations:

1. All organizations that have not yet completed Remediation and Testing of mission-critical electrical systems should do so as soon as practical.
2. All organizations that have a limited number of exceptions should identify those to NERC for tracking and report the rest of the program as Y2k Ready.

2.4 Entities That are Y2k Ready or Y2k Ready With Limited Exceptions

For the first time, the electric industry is able in this report to identify organizations that are Y2k Ready or Y2k Ready With Limited Exceptions. The exception process is described in Section 2.5.

The reasons for moving to a readiness disclosure at this time are:

- To respond directly to the DOE charge in May 1998 for NERC to assure electrical systems are ready to operate into the Year 2000 by July 1999.
- To provide further incentive to accelerate programs at organizations that are not currently Y2k Ready.
- To provide recognition to the organizations that have stepped up and met the challenge of making their systems Y2k Ready in accordance with the industry target and criteria.

Appendix B provides a list of the 251 organizations that are recognized by NERC to have met NERC Y2k readiness criteria for mission-critical electrical systems. Based on the data received, NERC believes that these organizations, both Y2k Ready and Y2k Ready With Limited Exceptions, will be able to operate reliably into the Year 2000.

NERC has based this list of organizations on data in the monthly NERC reports and receipt of a written readiness statement from an officer of each organization.

Recommendations:

1. NERC encourages all other electric organizations in North America to provide a Y2k public readiness disclosure.
2. NERC will continue to update the Y2k Ready list on a monthly basis, as additional organizations provide disclosure statements and supporting information, and as exceptions are completed.

2.5 Exception Reporting

Recognizing that some Remediation and Testing may extend beyond the June 30, 1999 target for some entities, NERC in January 1999 initiated an Exceptions Report process to allow more detailed identification and tracking of specific line items that would be completed after the target date. This exception reporting

process allows more precise reporting and analysis and a more accurate assessment by NERC of the reliability impacts of these schedules. An analysis is provided below and the exception list is provided in Appendix C.

There are currently 63 organizations reporting non-nuclear exception items.³ All reported exceptions appear reasonable and do not affect the ability to operate reliably into the Year 2000. All work and testing are scheduled for completion before the end of the year, with the vast majority of the items to be completed in the third quarter of 1999.

The exceptions are not included in the summary information reported above in Section 2.2. In terms of level of effort in the three phases, the exceptions represent a small fraction of 1% of total Y2k efforts and therefore the 99% completion of Remediation and Testing for the industry is unaffected. The exceptions do affect the reported Y2k Ready dates, as the exception items are not shown in the Y2k Ready dates in Section 2.2 above. The Y2k Ready dates for the exceptions are provided in Appendix C on an item-by-item basis.

The exceptions that have been reported are principally in five categories: emissions monitoring, SCADA/EMS, generating unit controllers, communications, and customer support systems. The nature of the exceptions is described below.

Emissions Monitoring — There are 18 organizations reporting 28 units that are pending upgrades and certification of Continuous Emissions Monitoring Systems (CEMS) after June 30. These numbers are believed to understate the number of units and organizations still working on making emissions monitoring systems Y2k Ready. However, emissions monitoring does not affect the ability of any unit to produce electricity. The impact is principally one of potential regulatory penalties if an organization is forced under emergency conditions to operate without CEMS. Because there is no direct impact on electric reliability, some organizations may not be reporting CEMS as mission critical for electric operations. Irrespective of the number of organizations and units affected, the industry is heavily dependent on vendors of these systems for upgrades and certification — and there appears to be a continuing backlog of demand for vendor support in this area.

EMS/SCADA — There are 26 Supervisory Control and Data Acquisition (SCADA) and Energy Management Systems (EMS) reported to have new upgrades that will require testing into the fall. Other control center computers and support systems are also reported as exceptions. Once again, this area is limited by availability of software and technical support from vendors. Taken individually, each of these exceptions seems reasonable. In most cases, the replacement system or upgrade is Y2k Ready and is pending final installation and testing. In other cases, the exception impacts only a small portion of the system. However, collectively 26 SCADA and EMS systems on the exception list

³ The status of nuclear facilities is addressed separately in Section 3.2.

warrants close monitoring over the next few months to assure that the work schedules are met.

Non-nuclear Generating Units — DCS upgrades and testing are expected in the fall of 1999 for 25 units. Miscellaneous controllers at another 19 units will complete Remediation and Testing during outages in the fall. Several others are reported as completing final integrated testing of the units in the fall, although the units will be tested at the component level prior to the target date. These exceptions are estimated to impact less than 30,000 MW or less than 4% of total non-nuclear generating capacity. The risk posed here is low, because demand during key rollover periods is expected to be no more than 50–70% of the summer peak. Even considering the need for extra operating reserves, the available generating capacity is well in excess of any credible demand during Y2k transition periods.

Communications — 14 entities report exceptions affecting voice or data communications systems, such as radio systems, microwave, LAN/WANs, and data acquisition systems.

Customer Support Systems — Customer billing, metering and service systems are reported by seven organizations due to new systems or upgrades planned in the fall.

Analysis:

About 24% of reporting entities indicate they have one or a few exceptions to the NERC target of June 30, 1999. The exception list, as summarized in Appendix C, does not present a risk to electric reliability for several reasons:

- The number and capacity of facilities is small and does not impact the ability to serve customers into the Year 2000.
- Some items have been tested at the component level and are pending final installation and testing.

Despite these assurances, exceptions related to SCADA/EMS, plant DCS and controllers, and communications are essential to reliable operations and warrant close scrutiny in the follow-up tracking process by NERC and DOE. It is apparent also that the greatest uncertainty in the area of exceptions is the ability of vendors to meet these stated schedules.

Recommendations:

1. Organizations reporting exceptions are requested to provide a monthly status report on each item in the exception report. NERC will publish a monthly update of the exceptions summary list.
2. These organizations should make a concerted effort to meet the stated schedules.

Section 3

Detailed Analysis of Y2k Readiness Second Quarter 1999

This section provides detailed results from the Y2k readiness assessment of electric systems based on data provided through June 30, 1999. Each technical area of the progress report includes major findings, an analysis of those findings, and recommendations. Supporting data are available for electronic download from the NERC Y2k web site at <http://www.nerc.com/y2k>.

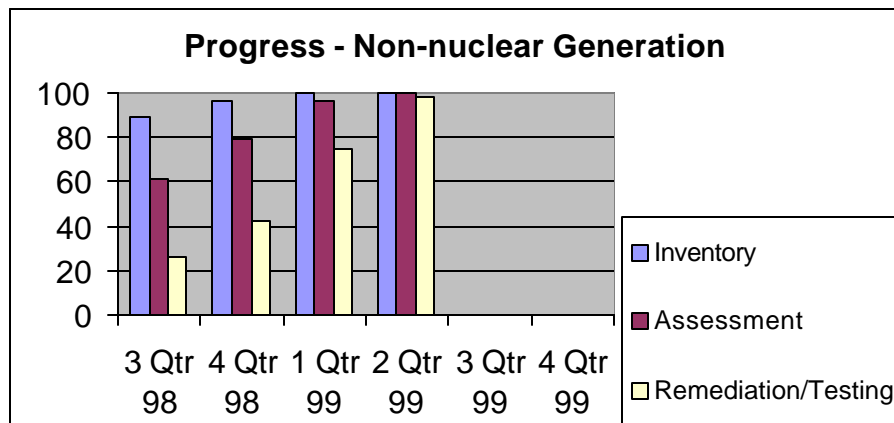
3.1 Non-Nuclear Generation

Findings:

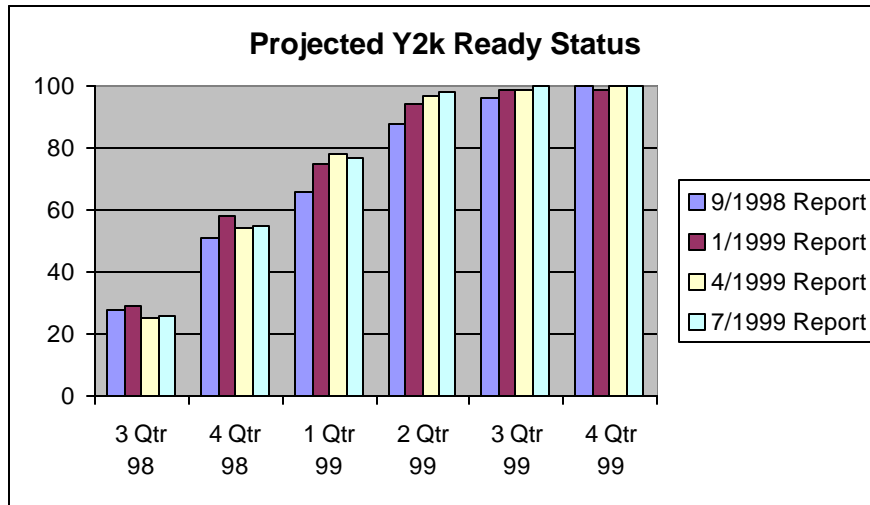
With 673,284 MW (92.9%) of non-nuclear generation reporting out of the 724,741 MW of total non-nuclear capacity in North America, the following progress is reported as of June 30, 1999:

Y2k Program Phase	Average Percent Complete
Inventory	100
Assessment	100
Remediation/Testing	98

The graph below indicates substantial progress in Remediation and Testing of generating units since the previous report. As of June 30, Remediation and Testing of generating units is nearly completed at 98%.



The second graph below indicates the estimated dates for achieving a Y2k Ready status for mission critical non-nuclear generation. The area of non-nuclear generation has slightly lagged the other technical areas tracked by the NERC report process. This is indicative of the challenges in scheduling maintenance outages for some plants to allow final testing.



Analysis:

Testing of non-nuclear generators continues to indicate a minimal number of failures that might cause an unremediated unit to trip. Fully remediated units are all expected to be able to operate into the Year 2000.

Of particular interest are the results of integrated tests involving the entire generating unit. It is estimated that more than 100 units at dozens of utilities have been tested while operating on line and producing power. These tests consist of simultaneously moving as many systems and components as possible to various test dates. These tests require an extraordinary level of preparation and coordination to ensure the safety of all systems and that the impact to the electric system would be minimal should a unit trip during the test.

Of all the integrated unit tests reported to date, not one test of a fully remediated unit has resulted in a Y2k failure that caused the unit to trip. In some cases, units that were moved forward to a post January 1, 2000 date have been left to continue running with clocks set ahead with no negative consequences.

Although these results are encouraging, there are cases in which components have required replacement or remediation. Examples of components that require particular attention include:

- DCS operator interface incorrect date display
- Computer controller BIOS operating system
- Data loggers incorrect date display
- Continuous emissions monitor data recording software or analyzer software
- Annunciator (alarm) systems
- Sequence of events recorder
- Precipitator controls

- Miscellaneous support systems – analyzers, recorders, etc.

Recommendations:

1. Any remaining non-nuclear plants that have not completed Y2k testing should be completed as soon as practical and the final status reported to NERC.
2. Additional integrated unit testing should be considered, as practical.
3. Controls should be adopted that assure Y2k Ready facilities remain ready.

3.2 Nuclear Generation

Nuclear facility Y2k programs are closely coordinated within the overall enterprise Y2k program. However, to take advantage of substantial work and leadership in this area by NEI, NERC requested that NEI provide an assessment of Y2k activities in the nuclear sector for incorporation into this report. The assessment by NEI is provided here.

In Generic Letter 98-01, the Nuclear Regulatory Commission (NRC) requested that each operational nuclear generating plant submit a report by July 1, 1999. The report was to "confirm that your facility is Y2k ready, or will be Y2k ready, by the year 2000 with regard to compliance with the terms and conditions of your license(s) and NRC regulations."

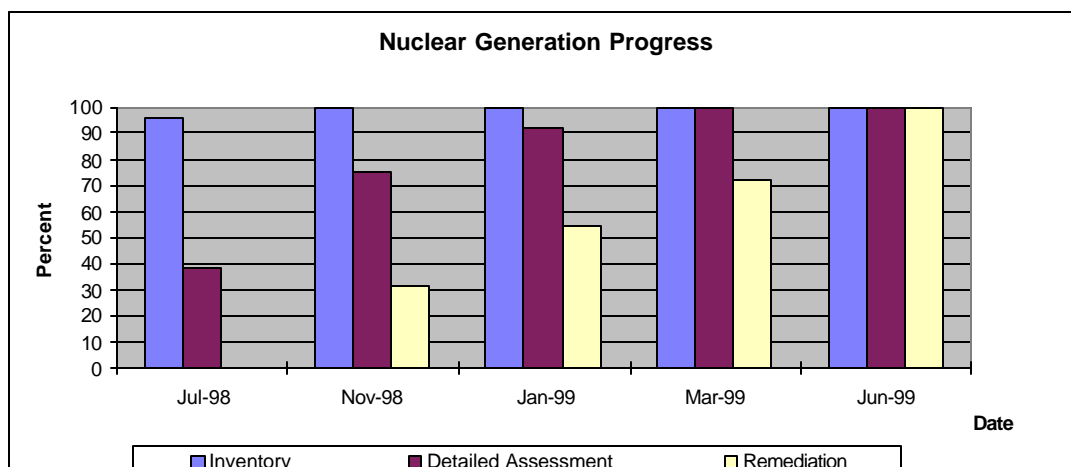
NERC requested readiness status of nuclear plants based on mission-critical items. The scope of nuclear generation's Y2k readiness program was much broader than the NERC reporting requirements. The nuclear program encompasses many additional items considered important by the nuclear plant managers. This summary is based on plant readiness reports submitted to the NRC and NEI. Status is reported based on the full scope of the nuclear program.

Findings:

With 100% of nuclear generation participating, the following progress is reported as of June 30, 1999:

Y2k Program Phase	Average Percent Complete
Inventory (Initial Assessment)	100
Detailed Assessment	100
Remediation and Validation	99 ⁺

The graph below indicates substantial progress in Remediation and Testing. As of June 30, Remediation and Testing was well over 99% complete.



Readiness reports identified only 58 items needing remediation and provided a scheduled completion date for each item. This list includes all open items that would be considered critical under NERC reporting criteria, of interest to the NRC, or important to the plant. A current list of open items, by plant, is available from the NEI web site at <http://www.nei.org>.

Based on the criteria discussed earlier in this report, all nuclear generation facilities are Y2k Ready or Y2k Ready With Limited Exceptions.

Status:

Each of the 103 commercial nuclear power reactors in the United States has reported the status of their Year 2000 readiness program, based on guidelines in *Nuclear Utility Year 2000 Readiness*. These programs apply to software, hardware, and firmware in which failure due to a Y2k issue could interfere with performance of a safety function or impact continued safe operation of the nuclear facility.

From industry reports, 68 reactors have completed all remediation and are Y2k Ready. Of the 35 reactors with work remaining, 14 report they are only remediating site support systems that do not impact reactor operations. There are 21 reactors remediating plant operating or plant support systems.

Over the past two years, the nuclear industry has tested about 200,000 items that could be susceptible to Y2k issues. Of these, about 5% — or 10,000 items — needed remediation. The industry has completed over 99% of the overall readiness program.

Each facility also prepared contingency plans for key Y2k rollover dates using guidance in *Nuclear Utility Year 2000 Readiness Contingency Planning*. These plans will reduce the impact of internal or external Y2k induced failures. Both industry guidelines are publicly available at the Nuclear Energy Institute web site at <http://www.nei.org>.

The NRC, the federal government's nuclear safety regulator, has been directly involved in the industry's Y2k readiness activity for the past two years, including on-site program reviews. NRC audits and on-site reviews have confirmed that nuclear power plants will continue to generate electricity safely and reliably into the Year 2000. The agency also concurs that all safety systems will function if required to safely shut down a plant. Independent NRC and industry audits have concluded that Y2k readiness programs have been properly executed.

The nuclear industry's Y2k effort has been closely coordinated with NERC. The current industry status leads to high confidence that nuclear generation plants

will continue to reliably deliver their share of the nation's electricity needs well into the next century.

Recommendation:

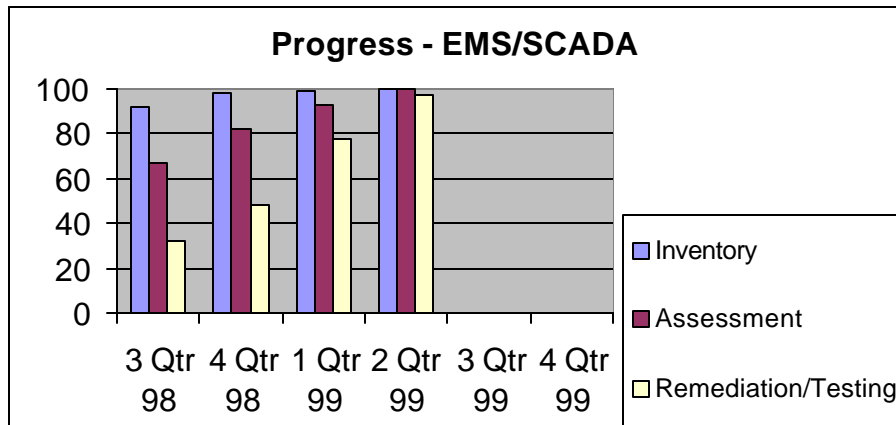
1. Nuclear generation plants should take action to finish open remediation items by the projected completion date. NEI and the NRC will monitor progress and completion of the 58 open items. An up-to-date status is posted on NEI's web site.

3.3 Energy Management Systems

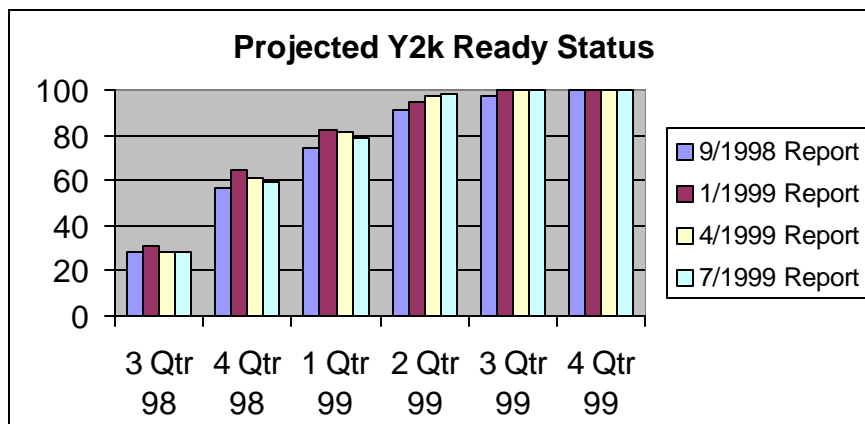
The following results are reported at the end of the second quarter 1999 for control center Energy Management Systems (EMS) and Supervisory Control and Data Acquisition (SCADA) systems.

Y2k Program Phase	Average Percent Complete
Inventory	100
Assessment	100
Remediation/Testing	97

As indicated in the graph below, EMS and SCADA systems are 97% complete in the Remediation and Testing phase. It is expected that remaining items will be completed in the third quarter of 1999.



As shown in the graph below, the projected schedule for achieving Y2k Ready status for EMS/SCADA systems has gradually improved, with the remaining few systems to be completed in the third quarter.



Analysis:

Most companies utilize commercial EMS/SCADA products. A few have ordered new Y2k compliant systems as part of their Y2k remediation approach. For those who have ordered new systems, Y2k testing may consist of factory acceptance tests in the vendor's shop. For these new systems, Y2k issues are typically resolved prior to delivery and installation. In some cases, delivery of new programs or upgrades past June 30, 1999 will result in final testing in late summer or early fall.

The types of Y2k issues being found in control rooms include incorrect date manipulations in:

- Client server hardware and software
- UNIX operating systems
- PC hardware and software
- PC operating systems

Recommendations:

1. Any remaining EMS or SCADA systems that have not completed Y2k testing should be completed as soon as practical and the final status reported to NERC.
2. Controls should be adopted that assure Y2k Ready facilities remain ready.

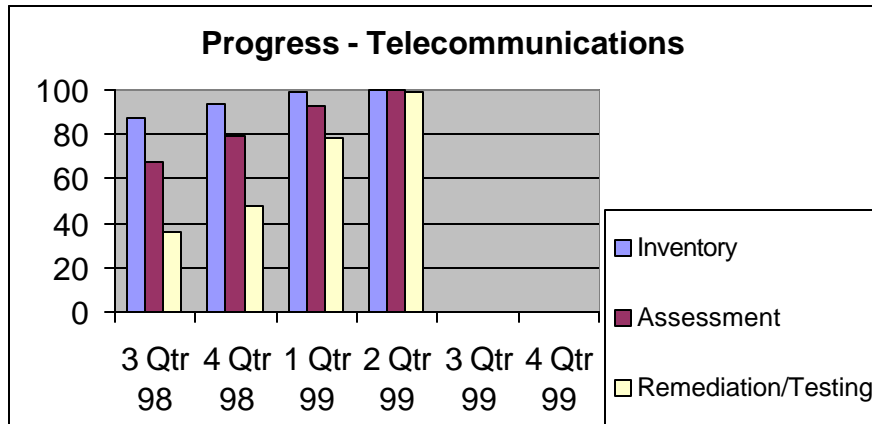
3.4 Telecommunications

Findings:

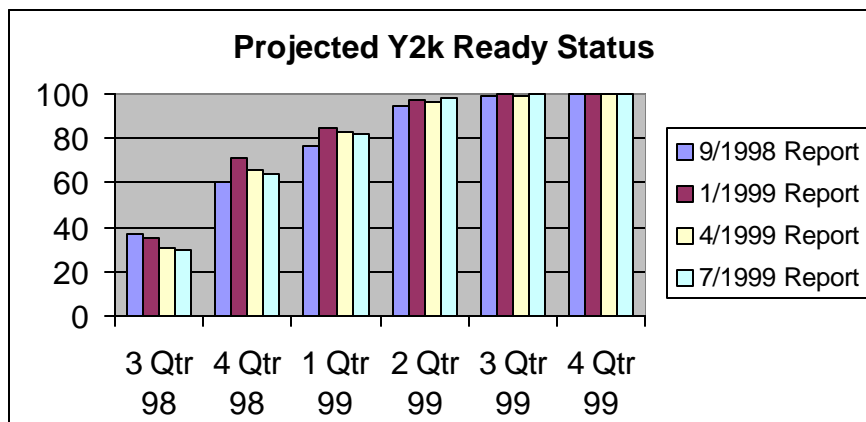
The following are the progress results in the second quarter 1999 for the internally owned and operated telecommunications systems used to monitor and operate electric supply and delivery systems.

Y2k Program Phase	Average Percent Complete
Inventory	100
Assessment	100
Remediation/Testing	99

Remediation and testing of electric utility owned telecommunications facilities has progressed well and is very close to complete with more than 99% done.



Final telecommunications items are projected for completion in the third quarter, as seen in the updated schedule below.



Analysis:

The electric industry owns and maintains a majority of its voice and data communications facilities. However, external service providers are used for a significant portion of voice and data communications. These external providers may be local telephone carriers leasing dedicated circuits to carry monitoring and control signals to power plants and substations. They also may provide long distance services, satellite systems, cellular systems, and wide-area networks. The electric industry, like many other industries, is dependent on a complex set of integrated communications systems.

Most entities report satisfactory progress in testing their internal communications systems, as reported above. Like EMS/SCADA and DCS systems, communications is an area that often requires support from vendors. Entities report making Year 2000 upgrades on older network equipment (e.g. routers, hubs, and switches). Often, testing procedures or results have been achieved with the assistance of or information available from equipment vendors.

It is apparent that extensive integrated testing with external voice and data communications service providers is not practical. Typically, these service providers are working hard to complete their own program and cannot dedicate substantial resources to joint testing with individual customers, including electric utilities. Also, these service providers typically cannot provide live circuits for end-to-end testing with electric systems, leaving most testing for the laboratory.

Examples of areas where Y2k anomalies have been discovered in electric utility owned communications systems include:

- Network management software
- Routers – primary functions work, diagnostics software may be impacted
- Control Signaling Unit/Digital Signaling Unit devices – incorrect date display
- PBXs – some require remediation
- Fax machines – incorrect date stamp

Partial loss of voice and data communications remains a high priority for contingency planning for electrical systems. Backup voice communications systems that do not have common failure modes with primary systems are the appropriate strategy for voice communications. These issues are discussed further under contingency planning in Section 4.

Recommendations:

1. Any remaining electric utility owned communications systems that have not completed Y2k testing should be completed as soon as practical and the final status reported to NERC.
2. Controls should be adopted that assure Y2k Ready facilities remain ready.

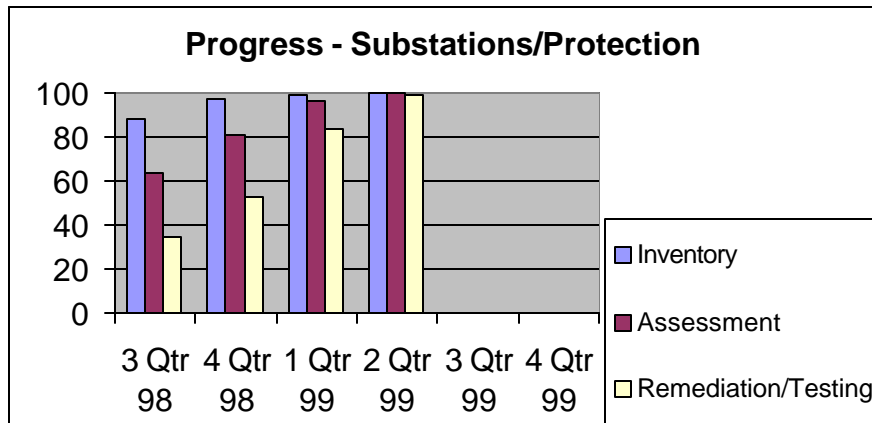
3.5 Substation Controls and System Protection

Findings:

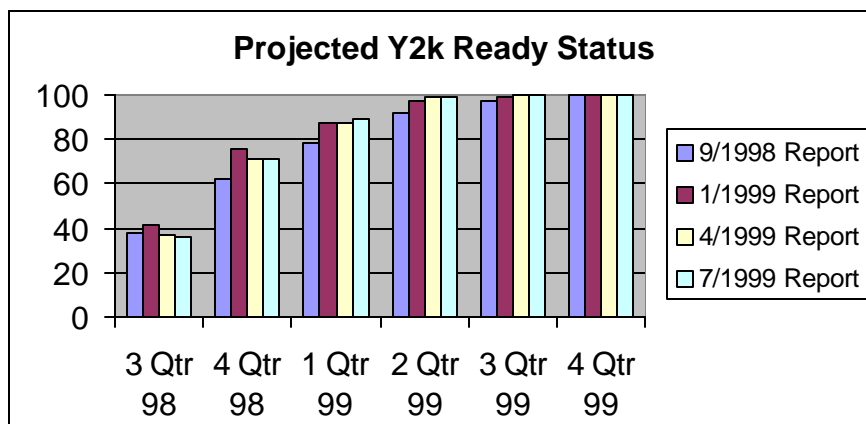
The progress by phase in the area of substation controls and system protection is provided below.

Y2k Program Phase	Average Percent Complete
Inventory	100
Assessment	100
Remediation/Testing	99

Work has progressed furthest in the area of substation controls and system protection.



Remediation and Testing in the area of substation controls and system protection will be completed in the third quarter of 1999.



Analysis:

Most entities report finding no system protection devices that would cause power interruptions or safety concerns as a result of a Year 2000 rollover in digital electronics. Some report minor issues with microchips and relays that may result in minor cosmetic results, such as two-digit years in logs. Entities report repair of these devices using vendor supplied chip upgrades. Many electric systems still utilize electro-mechanical relays, which are not date sensitive. Most report known work around procedures for cosmetic problems.

The types of Y2k issues being discovered include:

- Protective relays – nuisance problems with incorrect date stamp when operated
- Sequence of event recorders – incorrect date displays
- Digital faults recorders – incorrect date displays
- Miscellaneous digital controllers (transformer tap, capacitor, voltage regulator) – nuisance problems

Some relays and devices do not recognize a leap year, but this condition exists in other years as well, is not unique to Y2k, and is not an operating problem.

Recommendations:

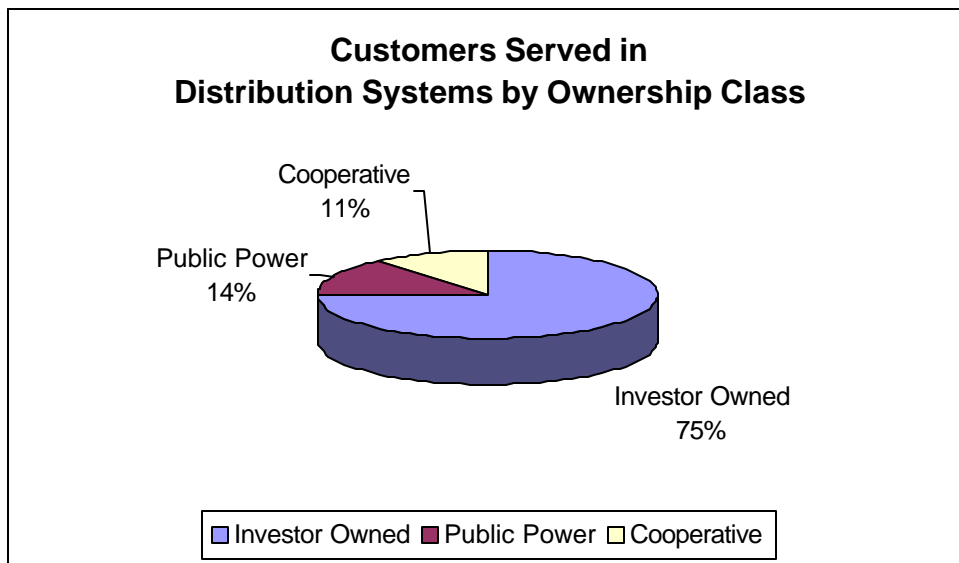
1. Any remaining substation controls or system protection components that have not completed Y2k testing should be completed as soon as practical and the final status reported to NERC.
2. Controls should be adopted that assure Y2k Ready facilities remain ready.

3.6 Distribution Systems

Background:

Due to the number (about 2,900) and diversity of distribution systems in North America, NERC has relied on the assistance of four electric industry associations (APPA, CEA, EEI, and NRECA) to collect information on the developing state of readiness of electric distribution systems. Due to the differences among industry segments, each association took a different approach to collecting assessment information. This section of the report is presented through the collaborative efforts of these four organizations.

The most recent EIA statistics show the following breakdown for customers served by distribution utilities in the United States:



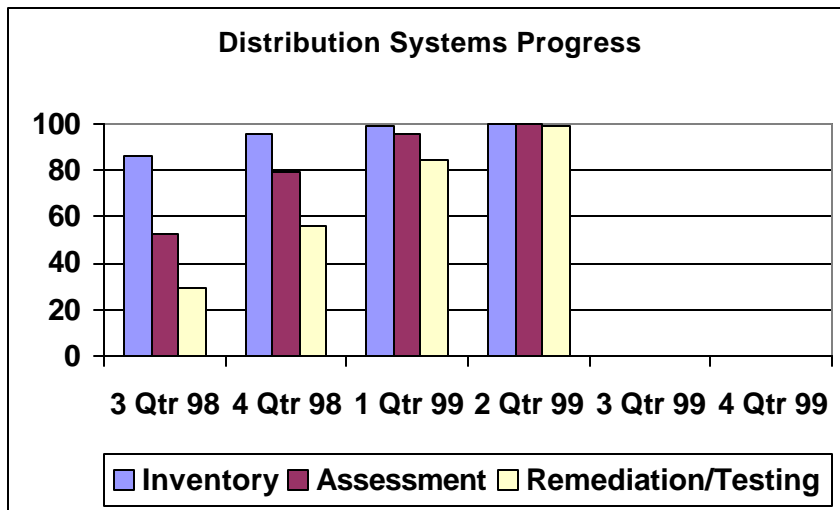
Status of Investor Owned Distribution Systems

EEI's approach, addressing the investor-owned sector of distribution systems, was to analyze the distribution system data provided by the NERC assessment reports. The majority of the investor-owned electric utilities are directly involved in reporting to NERC in all assessment categories, including distribution. This approach also allows EEI to assess distribution system status of investor-owned utilities that are not part of EEI's membership.

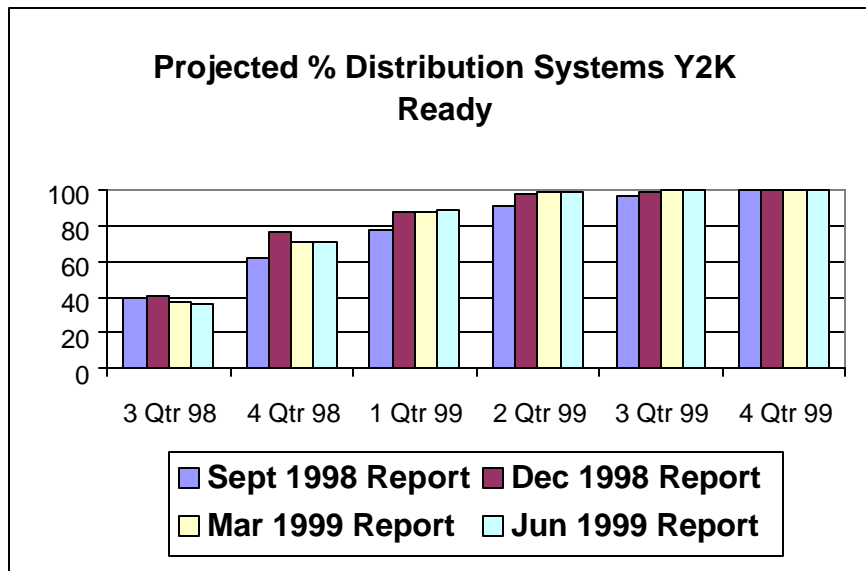
Indicated below is the second quarter 1999 Y2k progress results for distribution system organizations responding to the NERC survey:

Y2k Program Phase	Average Percent Complete
Inventory	100
Assessment	100
Remediation/Testing	99

The graph below indicates that distribution systems reporting to NERC are nearly complete, at an average of 99%.



The graph below shows that distribution systems reporting to NERC are tracking at a similar pace to other technical areas.



Status of Public Power Distribution Systems

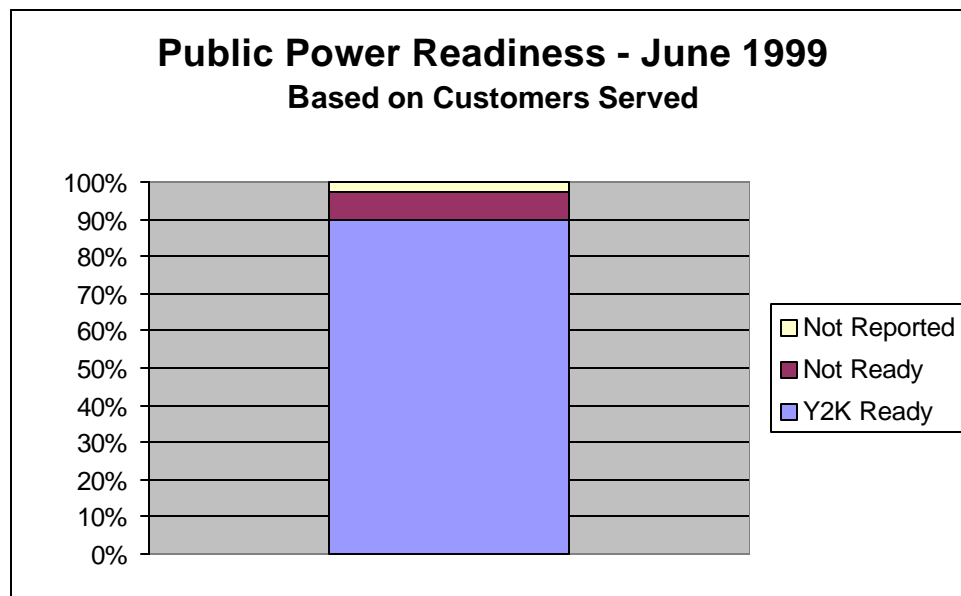
APPA's approach is a continuing one. To date, APPA has received responses from almost 99% of all systems, representing almost 100% of the customers served by public power. APPA also has included Y2k readiness information from the Virgin Islands, Guam, American Samoa, and Puerto Rico.

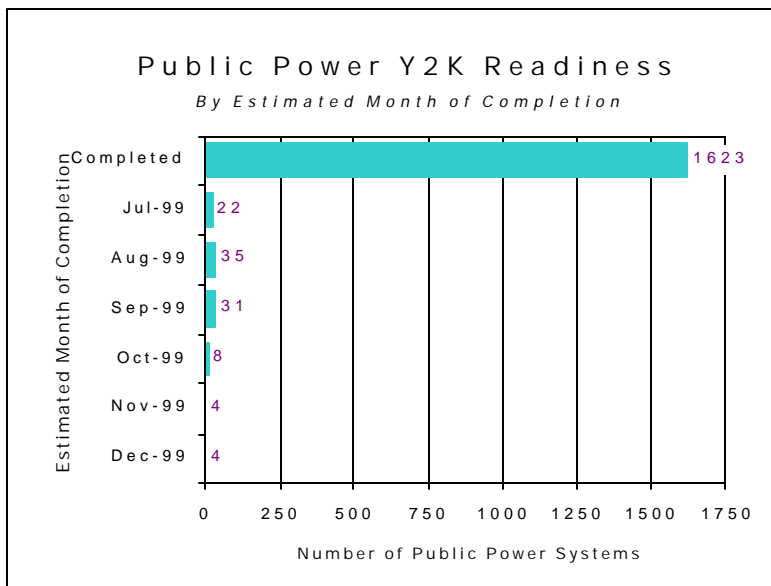
In 1998, APPA developed a three-tiered survey to assess the current Y2k status of APPA member and nonmember public power systems. Over 2,000 surveys were sent out, followed by a phone survey starting in October 1998. The first tier was a comprehensive three-page survey sent to the largest 240 systems. The second tier was a two-page survey sent to the middle 538 systems. The remaining systems, those with less than 3,000 customer meters, received a simplified one-page survey.

During the first quarter of 1999, APPA surveyed all systems greater than 3,000 customer meters, and surveyed all 2,000 public power systems again in June 1999 via a phone survey.

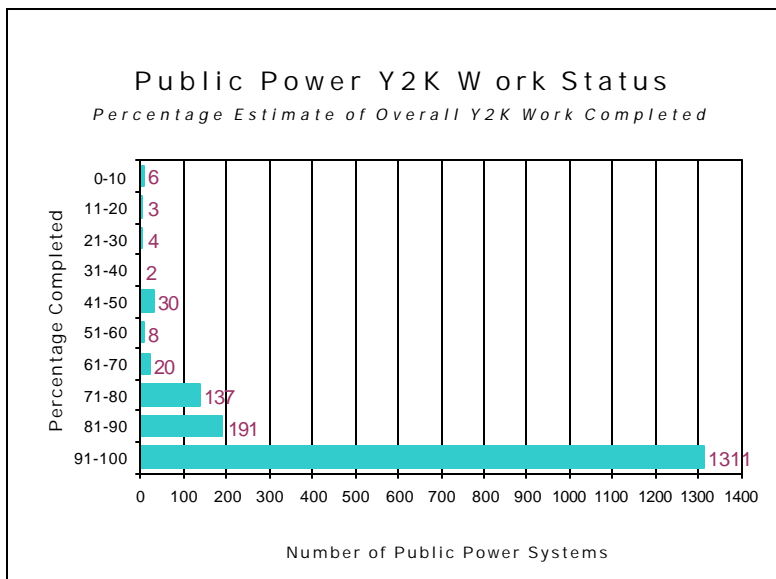
The APPA results reported below for the second quarter of 1999 are based on the 1,737 responses received during June 1999 (86.37% response rate). These results represent close to 98% of the customers served by public power entities.

Of the 1,737 organizations responding to questions about the expected Y2k readiness dates, 1,623 systems (93%) reported that they have attained Y2k readiness for critical delivery of electrical services. By the end of the third quarter of 1999, 98% of all systems will be Y2k Ready. Supporting charts are provided below. Detailed data for public power systems are provided in Appendix D.





As of June 1999, 1,623 public power organizations report completion of their Y2k Ready status for electrical systems. These Y2k Ready organizations represent about 90% of the customers served by public power entities. The remaining respondents indicate they expect to be Y2k Ready on the dates shown.



For the 1,712 APPA survey respondents providing Y2k Work Completion estimates, the average work completed was 95%. The chart to the left shows how that average is distributed among the respondents.

As public power systems move from Y2k testing to contingency planning in the latter part of 1999, the most recent APPA survey indicates that 92% of mid-sized systems and 96% of the larger systems have specific Y2k contingency plans. Others will utilize existing contingency plans based on years of operation as transmission-dependent utilities.

In the area of Y2k program audits, APPA's survey indicates that almost 93% of public power systems are performing some sort of audit — internal, external, or both. Additional details of the APPA survey are available in Appendix D.

Status of Cooperative Distribution Systems

NRECA's approach started with a telephone survey of 875 rural distribution systems, including NRECA nonmembers, in August 1998. Questions about generation were not posed to rural electric distribution systems, as they do not control generation assets. The generation and transmission (G&T) cooperatives that do own generation are reporting through the NERC process.

Information from the August 1998 survey established a baseline set of data on the amounts and types of equipment at each distribution cooperative. That data was used to divide rural electric distribution cooperatives into two groups for the fourth quarter survey conducted in early December 1998. 600 cooperatives that have minimal or no Y2k-sensitive equipment were faxed a four-page abbreviated form. The remaining 275 cooperatives were faxed an eight-page survey similar to the NERC form.

At the outset of the third quarterly survey, NRECA and APPA determined that both organizations were surveying a small subset of members in common. With APPA's input, NRECA finalized a list of 858 rural electric distribution systems, thus accounting for the members in common with APPA. The list was also updated to include several recent cooperative mergers.

In March 1999, NRECA faxed a five-page survey to all 858 systems, requesting a fax reply. The survey form encompassed NERC's questions on EMS/SCADA, telecommunications, substations/distribution, and a new section containing questions about the relationships between the distribution cooperatives and their wholesale power suppliers. Uncertainty about bulk power supply readiness was the major concern expressed by cooperatives prior to this survey.

The fourth survey conducted by NRECA at the end of June 1999 covered 858 distribution cooperatives. NRECA reviewed the March 1999 data to determine patterns in readiness dates, anomalies in answers (such as testing completed in June but not ready until December 1999), and strong use of digital electric distribution technologies. Cooperatives that fell into one of those categories were faxed a detailed form, essentially the same as they had received during previous surveys. The rest of the cooperatives were faxed a one-page form containing questions derived from NERC's Y2k readiness "benchmarks": regular reports to boards of directors, written plans, completion percentages and dates for the phases of Y2k work defined by NERC, and other questions.

NRECA agrees with NERC's analysis of testing completion dates versus Y2k ready dates as discussed in the April 30 report (see p. 19 — Analysis). That is, NRECA believes that a small number of items are driving overall completion schedules.

In addition, some cooperatives continue to include non-mission-critical (as defined by NERC) systems, equipment and applications in the overall readiness reporting. Therefore, those cooperatives may be slightly under-reporting readiness milestone achievements as well as providing a "Y2k-Ready" date beyond June 30, 1999. NRECA endorses NERC's definition of mission-critical items, and continues to recommend that its member cooperatives report within this overall industry process in that light.

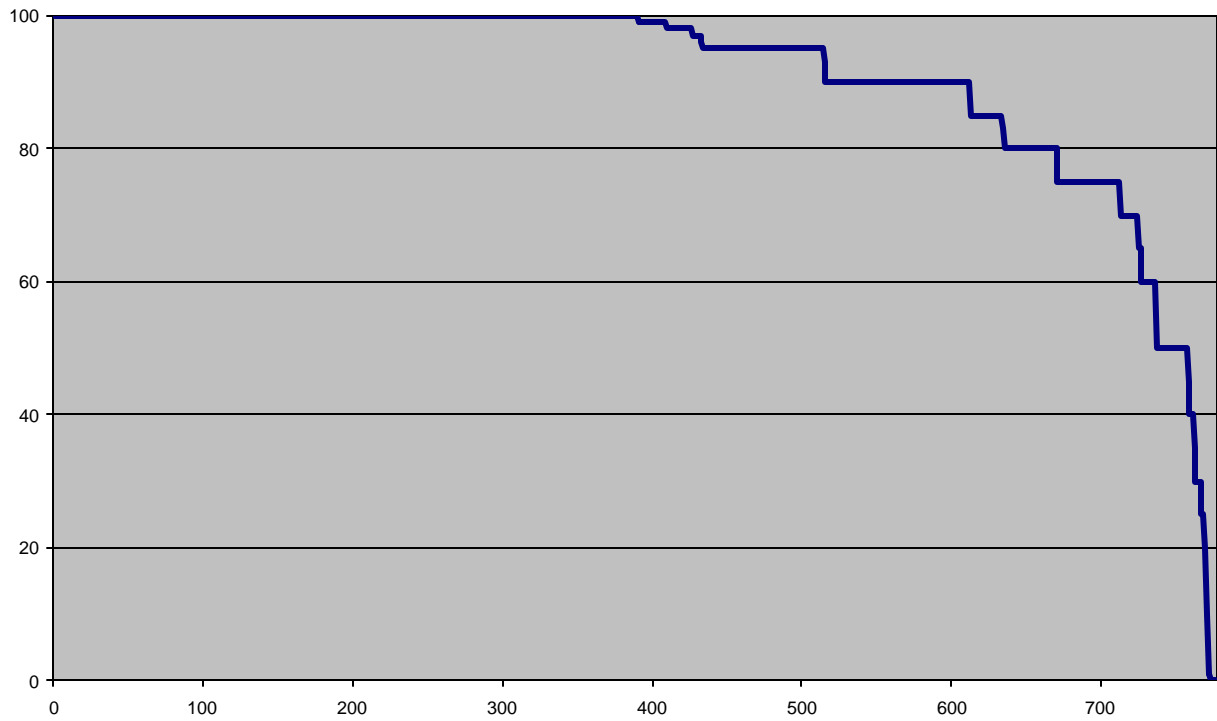
NRECA did not include questions about power or transmission supplier readiness and relationships as in March. The results of the March survey showed overwhelmingly that cooperatives appear to be satisfied with Y2k-related communications from bulk power and transmission suppliers, as well as with the state of readiness at those same suppliers. In addition, the progress toward readiness of all bulk power and transmission suppliers taking part in the industry coordination process with NERC, as demonstrated in past quarterly reports, provides some reassurance.

NRECA received 821 (96%) responses to its June 1999 survey indicating completion of 99% of Inventory, 98% of Assessment, and 91% of Remediation and Testing. About 25 cooperatives that did not respond in June repeatedly reported Y2k ready dates ranging from December 1998 through June 1999 on previous surveys. NRECA has detected a reluctance on the part of cooperatives, who have been ready for months and previously reported that readiness, to continue the paper chase of quarterly reporting.

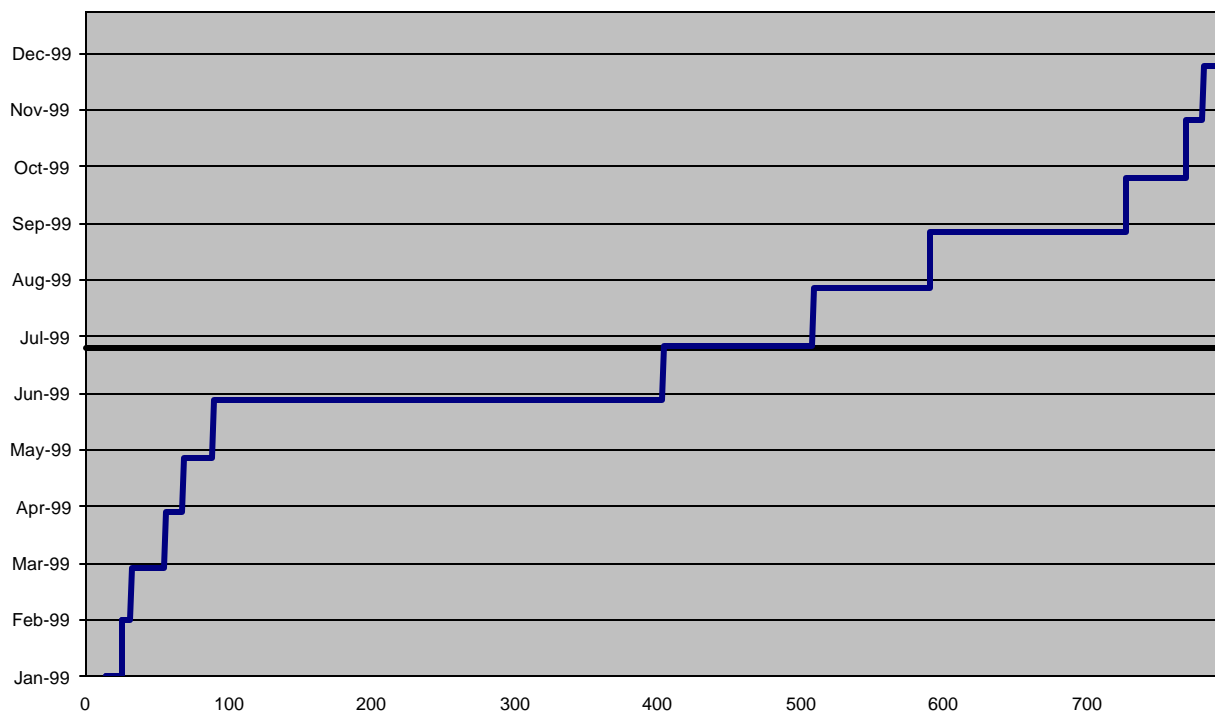
Rural electric cooperatives provide service to 13,840,998 meters throughout the United States. Based on reporting by cooperatives throughout the NERC coordination process, cooperatives serving 11,903,258 meters are Y2k Ready. Cooperatives serving 1,799,330 meters are not Y2k Ready, but will be by the end of 1999. The status of cooperatives serving 138,410 meters currently can not be determined.

Additional details from the NRECA survey results may be found in Appendix E.

% Complete Y2k Testing - 6/30/99
776 Reporting Rural Electric Cooperatives



Y2k Ready Dates for
793 Reporting Rural Cooperatives



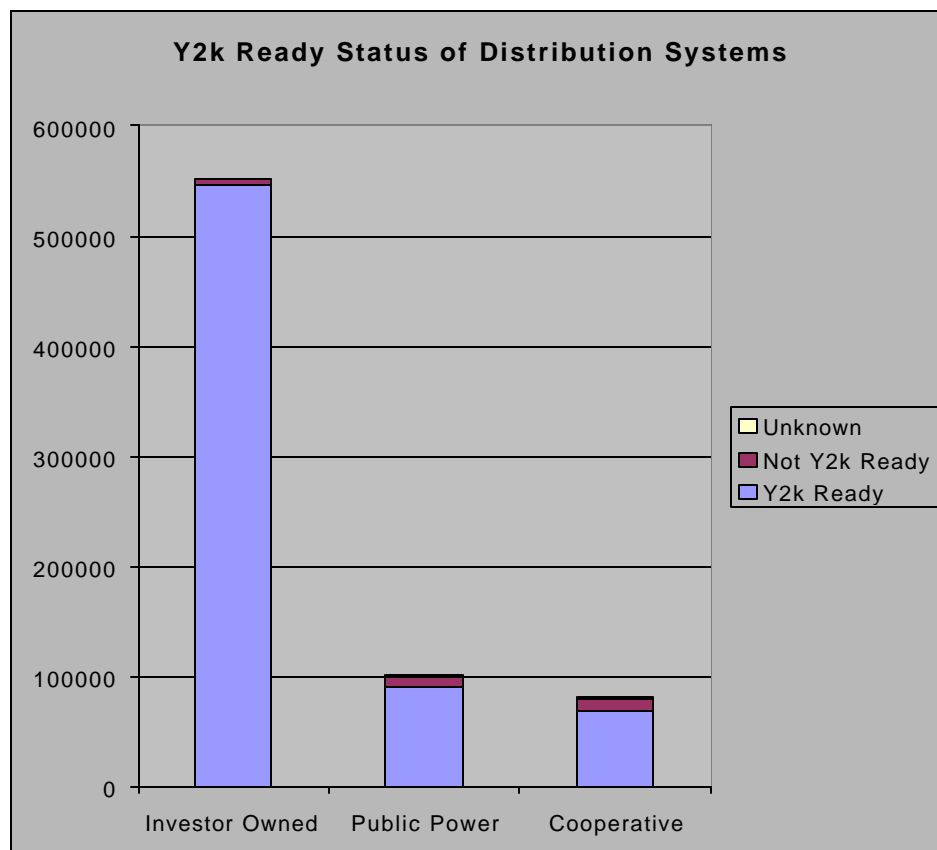
Summary Analysis:

The graphic below summarizes the Y2k readiness status of distribution systems by owner class. Investor-owned distribution systems report directly to NERC and account for 75% of customers served. The investor-owned distribution systems are 99% complete in terms of load served and 98% in terms of number of organizations reporting to NERC (four organizations were not 100% complete with distribution systems as of June 30, 1999).

Public power distribution systems serve about 14% of load in the United States. Based on data received in the second quarter of 1999, distribution systems serving about 90% of the load served by public power report they are Y2k Ready, 8% are not Y2k Ready, and 2.5% are unknown.

Cooperative power systems serve about 11% of load in the United States. Based on data received in the second quarter, 86% of cooperative systems report being Y2k Ready, 13% are not, and 1% is unknown.

As shown by the graph below, the vast majority of customers are served by distribution systems that have been verified to be Y2k Ready.



Of the distribution organizations reporting in this section, only a minority makes extensive use of digital electronics and SCADA systems. Nearly a third, in fact, do not rely on digital systems for the delivery of electricity at all. Where digital components do exist, they may be found in SCADA systems, voltage regulators, reclosers, meters, recorders, relays, capacitor controls, automatic transfer switches, time-of-use meters, and communications interfaces. These devices were evaluated, assessed, and tested for Y2k readiness. The vast majority have been fixed or replaced.

Of the Y2k related problems found at distribution entities, most are related to date-sensitive electric meters, time-switched capacitors and voltage regulators, and fault recorders. Nearly all of these manifestations are not mission critical to the reliable delivery of electric power to ultimate consumers. However, these devices are being replaced or remediated, as necessary.

Recommendations:

1. All distribution organizations whose mission-critical items were not ready by June 30, 1999 should plan to have mission-critical systems and components Y2k ready as soon as possible.
2. Distribution entities should prepare Y2k plans including special operating procedures, training, contingency plans, and emergency response plans.

3.7 Business Information Systems

Background:

Although business information systems generally do not have instantaneous impact on North America's power supply, some of these functions may be necessary for the sustained operation of the organization. Electricity providers must have the continuing ability to service customers, order fuel supplies, pay their work force, and locate equipment in the field.

The Y2k effort in business information systems typically started much earlier than most Y2k efforts in the power generation, transmission, and delivery areas and has evolved to become part of the corporate Y2k effort. There are many factors that determine the specific approach to a utility's business information systems Y2k effort. These factors include the age of the existing systems, pending mergers/acquisitions, and the current or future regulatory climate in the state(s) in which the utility operates. Typical approaches to addressing the business information system Y2k issues include replacing systems, fixing existing systems, and retiring systems that are out of date and no longer needed to support the business.

The readiness assessment of business information systems was done with the cooperation of APPA, CEA, EEI, and NRECA. This section of the report is based on NERC assessment reports and was prepared by EEI.

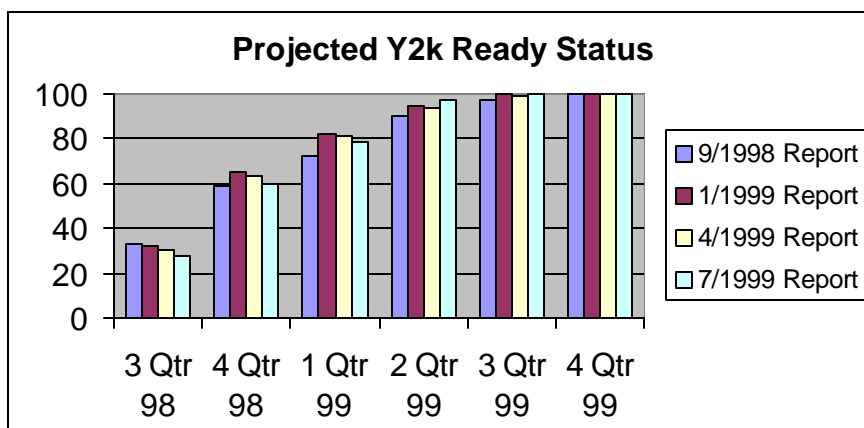
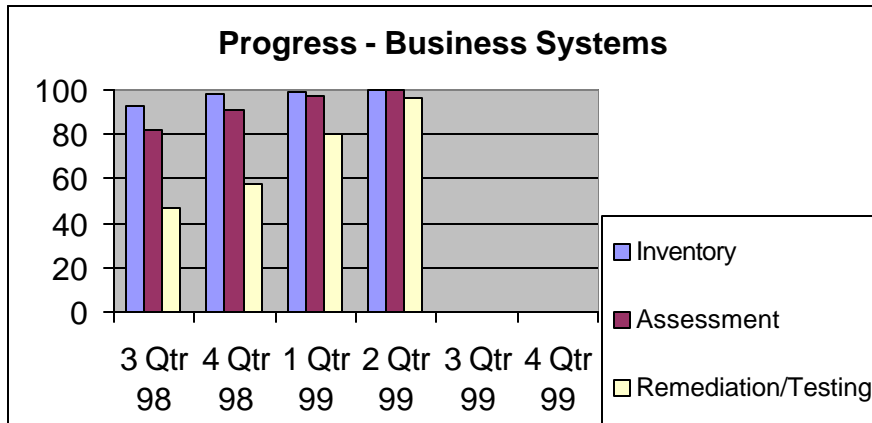
Findings:

The following are the results in the second quarter of 1999 for business information systems at electric supply and delivery organizations responding to the NERC survey:

Y2k Program Phase	Average Percent Complete — 2nd Qtr 99
Inventory	100
Assessment	100
Remediation/Testing	96

Analysis:

To date, 238 electricity providers have responded to the business information systems portion of the NERC survey. The readiness of business information systems continued to improve during the three months since the first quarter 1999 report with 100% of Inventory, 100% of Assessment, and 96% of the Remediation and Testing efforts completed. All organizations responding to the NERC survey expect to be Y2k Ready in the third quarter.



It is interesting to note that business information systems are no longer at a higher percentage of completion than the other areas of the NERC assessment, even though the Y2k effort for business systems generally started much earlier. Program managers report that the business information systems have been the most difficult area to finalize. Some of the reasons cited include:

- Difficulty in testing distributed systems due to the complexity of those systems and information relationships
- Network components are difficult to test thoroughly, as real-world environments are difficult to replicate for testing purposes
- Vendors have changed their compliance statements concerning software and hardware
- Waiting on vendors to supply Y2k fixes, or waiting for certification and testing of outsourced systems before Remediation and Testing can be completed
- Large business systems upgrade and replacement projects are taking longer to complete than anticipated
- Rapidly changing business environment that has delayed some Y2k efforts

Y2k-related issues are being discovered in the following business- or facilities-related areas:

- Mainframe computers
- Servers — operating systems
- PCs — hardware and operating systems
- Software applications
- Heating, ventilation, and air conditioning (HVAC) systems
- Security access systems

Recommendations:

1. Organizations should adjust schedules and apply the necessary resources to complete the Remediation and Testing of the few remaining items in their inventory immediately.
2. Controls should be adopted that assure Y2k Ready facilities remain ready.

Section 4

Contingency Planning and Preparations

4.1 Goal of Contingency Planning

The NERC Y2k Program uses a “defense-in-depth” concept. Test results into the second quarter of 1999 continue to indicate that Y2k failures do not appear to be of the type that would cause properly remediated electrical facilities to trip out of service. However, the consequences of wide spread or extended outages, however improbable, are so significant that the industry does not plan to stop simply with testing and repairing equipment. Contingency planning is an important step in assuring that electric systems are operated in a manner such that operating problems are handled without resulting in a loss of electric service to customers due to Y2k.

4.2 NERC Y2k Contingency Planning Guide

NERC has developed a guide to Year 2000 contingency planning and preparations for the electricity supply and delivery systems of North America. The goal is to mitigate operating risks to achieve reliable and sustained electric operations during the transition into the Year 2000 and beyond.

This guide is intended to address all aspects of electric power production, transmission, and distribution in North America. The guide is available on the NERC Y2k web site at <http://www.nerc.com/y2k>.

The following steps outline the NERC process for Y2k contingency planning and preparations. These steps are intended as a general guide. Regions and operating entities are expected to develop contingency plans that meet their specific requirements.

Step 1: Identify Y2k Operating Risks

Step 2: Conduct Y2k Scenario Analysis

Step 3: Develop Risk Management Strategies

Step 4: Implement General Preparations

Step 5: Plan Power System Operations during Y2k Periods

Step 6: Implement the Y2k System Operating Plan

4.3 Organization and Responsibilities

The effort of preparing electric systems for operation during critical Y2k transition periods must be coordinated at several levels. NERC is coordinating contingency planning and preparations at the Interconnection and interregional levels. NERC will review the contingency planning and preparation efforts across

all ten Regional Reliability Councils. NERC has formed a special Y2k Contingency Planning Task Force to facilitate this effort.

Regional Reliability Councils will coordinate efforts within their Regions and with neighboring Regions. This includes intra- and interregional studies and preparations. Regional Reliability Councils will assure participation of members of the Region.

Organizations that operate generation, transmission, or distribution systems will participate through the Regions in this contingency planning and preparations effort.

4.4 Report of Contingency Plan Review

In October 1998, NERC requested that all bulk electric system operating entities in North America prepare a first draft of Y2k contingency plans by December 31, 1998 and final Y2k contingency plans by June 30, 1999. The ten NERC Regional Reliability Councils reviewed the draft and final contingency plans. The results were reported to the NERC Y2k Contingency Planning Task Force in January 1999 and July 1999. The following results were achieved:

- All bulk electric entities have developed Y2k contingency plans in accordance with NERC guidelines. A list of bulk electric system entities whose contingency plans have been reviewed by NERC and the ten Regional Reliability Councils is provided in Appendix F.
- The contingency plans have been determined to meet the objectives of the NERC guidelines and to satisfactorily address credible risks associated with Y2k.
- Contingency plans have been coordinated and integrated on a Regional and interregional basis.
- Contingency plans are supported by operating and engineering analysis of Y2k risks and mitigation strategies.

4.5 Summary of Risk Mitigation Strategies

Contingency plans express the specific operating and response plans of each operating entity and each Region. It is necessary that these plans be customized to local reliability requirements. However, there are several common threads that run through all entities and Regions:

- Staffing Critical Facilities — During the Y2k transition periods, operating entities are planning to place additional operating and technical personnel in essential substations, power plants, operating centers, and other key facilities. In most cases, steps have been taken to curtail vacations and adjust staffing schedules during the critical periods. These additional personnel will allow more secure operations and a timely response to any conditions that may arise during the Y2k transition period. Additional

computer support, communications, and management personnel will also be available at key locations to assure continuity of essential services and information. Personnel are being trained in their roles and are being provided opportunities to practice those roles during the NERC Y2k drills, as well as, in some cases, other company drills.

- Back-up Communications — As previously described in this report, voice and data communications are perceived to be the greatest vulnerabilities of reliable electric system operations. To address this dependency on communications, electric power organizations are using existing and newly installed redundant communications. Mobile radios, satellite phones, internally owned PBXs, cell phones, and other systems afford electric utilities two, three, and in some cases four independent ways to communicate with operating personnel. Practicing the use of back-up voice communications has been the focus of the NERC Y2k drills. With a possible loss of data communications, a bare minimum of operating information may be transferred by voice to the control center to allow continued safe and reliable operation. Manual data transfer is slow and limited in the amount of data that can be transferred, however, it was proven effective during the April 9, 1999 Y2k drill.
- Commitment of Additional Generation Resources — All operating entities are planning for the provision of additional generation resources during the Y2k transition periods. In most cases, base-loaded units will be backed off from maximum output to some lesser amount. This reduced base-load unit output will permit starting additional units, which normally would not run during the long New Year holiday weekend. Most units will be operating at a reduced output that is above the minimum but below the maximum allowable for the unit. This approach allows the system operator maximum flexibility to increase or decrease unit outputs in response to higher or lower-than-expected customer demands. Some units may be running but synchronized to their own plant loads rather than the Interconnection. This approach allows the unit to operate as a reserve that can be synchronized within a few minutes, if needed.
- Nuclear Plants Operate Normally — Nuclear plants are expected to operate at either normal output or in some Regions at levels slightly below maximum output such as in the 80–95% range. Backing off nuclear units allows greater flexibility to the system operator by allowing room for other types of generation. Nuclear plant operators and system operators will finalize operating strategies for the nuclear facilities based on assuring the utmost of safety with these plants and meeting the electrical needs of the power system.
- Increase in Operating Reserve Requirements — Operating reserves consists of extra generating capacity that is either spinning on line or available to start and provide electricity within ten minutes (the timing requirement may vary on some systems). Normally operating reserves would cover the largest single contingency on the system. If operating reserves are used, such as following the loss of a generator, the system operator quickly restores the reserve

amount by scheduling additional generation on line, thus preparing for the next possible contingency. During the Y2k transition periods, minimum operating reserve requirements will be increased to at least two to three times normal operating reserve requirements. With the number of additional units committed to operate, actual operating reserves are expected to be much higher than the minimum requirement.

- Reduce Transfer Limits on Bulk Transmission System — Most systems are considering a some reduction in the amount of energy transfers they will allow across key transmission facilities. This strategy ensures transmission lines, transformers, high voltage DC systems, and other transmission facilities are not loaded to their maximum transfer capability. For example, a group of transmission lines that make up a power transfer interface may be limited to 80% or 90% of its normal maximum rating to allow greater flexibility and security. Transfers may also be limited to amounts below settings that would arm special protection schemes, such as the islanding schemes in the Western Interconnection. Reducing transfer limits will not impact the ability to serve customers, because there will be an abundance of generation on line. So much additional generation is expected to be available that transfers should be lower even than they normally are during a holiday weekend.
- Fuel Supply Flexibility — Fuel supply is not expected to be a major risk for electric operations. Coal and oil supplies will be assessed to assure adequate supplies are on hand at the generator. Many organizations are temporarily increasing the supplies above normal levels. Natural gas supplies are for the most part in the gas pipeline. Availability of natural gas is being coordinated with those suppliers. Reservoirs that supply hydroelectric facilities will be adjusted to ensure maximum reserve capacity is available. Pumped storage facilities will be in a position to either pump or generate depending on system demand. Although fuel supply is not seen as a major risk, the strategy is to maintain maximum flexibility to use alternative types of fuels.
- Curtail Short Term Maintenance — Most organizations plan to make all generation, transmission, and distribution facilities available for operation during the Y2k transition periods. This approach requires the curtailment of maintenance activities that might normally result in a portion of facilities out of service. Some facilities that are in a major overhaul or under construction may be excluded.

4.6 Y2k Transition Periods

One aspect of contingency preparedness is identification of the key transition periods. Each Region and company was allowed to assess risks and establish a plan to commit personnel and other resources. There were differences in view as to the start time and duration of the key transition periods. The shortest period suggested was two hours prior to midnight December 31 until two hours after. The NERC Y2k Contingency Planning Task Force reviewed risk factors

associated with the transition to the new century and identified the following as the key Y2k transition periods for operation of electric power systems:

- 6 p.m. EST December 31, 1999 to Two Hours Past Midnight Local Time — During this transition period, operating entities are requested to be at the maximum state of operational readiness. 6 p.m. EST has been selected to correspond to one hour prior to the midnight rollover of clocks referenced to Greenwich Mean Time (GMT). A portion of communications, energy management systems (EMS), and supervisory control and data acquisition (SCADA) systems use clocks referenced to GMT. These clocks do not directly affect the production and delivery of electricity, but they do support a number of measurement, transaction, and information management services in the control center. This initial key transition period should continue until at least two hours past midnight local time. This duration allows sufficient “soak time” past midnight to determine if any anomalies have occurred. Each operating entity is requested to prepare criteria and instructions for the termination of the alert condition and release of personnel. It is recommended that this release require a positive communication from the appropriate operating authority.
- January 3 Load Pickup — The load pickup on the first business day of the Year 2000 on Monday, January 3 is also a key transition period. Typically, the load pickup period would extend from about 6 or 7 a.m. local time until midday. Considering the uncertainty of customer activities on the first business day of the Year 2000, electric systems should be in a heightened state of alert. The level of resource deployment should also consider the results from the initial transition period.
- Ramping of Generation Resources — To put additional generating units in service, it may be necessary to ramp units up or down to arrive at the most conservative configuration for the New Year transition period. It is recommended that this shifting of resources be conducted gradually going into and out of the transition period. This gradual shifting may require a one to two-day period to implement.
- Maintenance Curtailment Period — There are no specific time recommendations for curtailment of short-term maintenance, other than it be implemented prior to the December 31 transition period. However, once again gradual changes to system configuration are preferred and practical limitations with staffing may dictate that the maintenance curtailment process extend for several days up to one to two weeks.
- February 29, 2000 — The leap year date transition into and out of February 29 is also considered a key Y2k transition date. Specific plans will be developed pending the results of the New Year transition.
- August 22, 1999 — This date is associated with the end of the calendar for Global Positioning Satellites (GPS). GPS signals are used to provide time stamps for some monitoring devices. The GPS satellites are expected to operate properly into and beyond August 22, 1999, and the impact of a failure

would be minimal on electric system operations. However, as a precaution NERC plans to issue an alert to security coordinators and control areas to be on a heightened state of awareness during this period.

4.7 Market Cooperation

The operating strategy outlined above (extra generation and reduced transfers) may have modest impacts on electricity markets. However, all users of the transmission system benefit from the added reliability afforded by these risk mitigation strategies.

Operating entities and Regions are working closely with electricity market participants to minimize market impacts while taking steps to assure reliability. In addition to the risk mitigation strategies previously described, the NERC Y2k Contingency Planning Task Force recommends the following steps to assure a smooth transition of electricity markets into the Year 2000:

- Voluntary Halting of New Transactions from 22:00 December 31 until 02:00 on January 1 — Operating entities are requested to implement and market participants are requested to honor a voluntary halting of new hourly non-firm transactions during this four-hour period. The time refers to local time of the operating entities involved in the transaction. It is anticipated that hourly non-firm transactions will be minimal during this period anyway, especially considering the large surplus of generation that is on, and therefore impacts should be minimal.
- Smooth Ramps of Schedules — Operating entities are requested to coordinate schedules that may be ending or starting near midnight on December 31. Being the start of a new year and a new month, and being the end of the week, could normally result in a larger-than-usual number of long-term energy transactions being scheduled in or out. To assure a stable transition, some operating entities may choose to spread the ramping period over a wider time frame to avoid sudden shifts around midnight on December 31.
- Provide Information to Market Participants — Operating entities are requested to provide information to market participants regarding Y2k operating plans and possible market constraints. These plans should be posted on the Open Access Same-time Information System (OASIS) of each provider and other forums as available. Operating entities and market participants are requested to work together cooperatively to develop and implement strategies to assure the highest level of system security during Y2k transition periods.
- Take Additional Steps as Necessary to Maintain Reliability — Operating entities may need to take additional steps beyond those outlined above to maintain a secure system in response to actual or perceived Y2k risks. Each operating entity already has the authority to take steps necessary to maintain a secure system.

4.8 Communications and Information Management

Communications plans are an essential element of an effective Y2k operating strategy. Communications plans already exist for coordination between electric systems and Regions, and within individual electric systems. These plans are being reviewed and upgraded as necessary for Y2k.

More than two years ago, NERC established 21 regional security coordinators to monitor power system conditions and coordinate steps to assure reliability. These security coordinators have access to information within their Regions and to a dedicated Hotline for interregional coordination. The security coordinators are installing satellite voice systems as an alternate communications channel during Y2k transition periods.

NERC is working closely with the U.S. Department of Energy (DOE) and the President's Council on the Year 2000 Conversion to develop interindustry information interfaces that will allow the gathering and dissemination of timely information from various critical infrastructure industries during Y2k transition periods. This process will also include same-day information from Asia, Australia, Europe, and other advanced time zones. The current plan is to staff the Y2k information centers continuously from December 29, 1999 until January 4, 2000.

Within each Region, control areas are able to communicate with each other and the security coordinator over alternate voice systems. Control areas also provide redundant communications systems over their geographic areas.

4.9 NERC Y2k Drill September 8–9, 1999

The goal of the September 8–9, 1999 NERC Y2k Drill is to provide the bulk electric systems of North America an opportunity to rehearse key portions of their administrative, operating, communications, and contingency response plans for the transition into the Year 2000. Three major objectives have been identified to guide development, implementation, and evaluation of the drill:

- Demonstrate the ability to effectively deploy resources and perform operating and administrative procedures related to the transition from December 31, 1999 to January 1, 2000;
- Demonstrate, under simulated conditions of a loss of one or more primary voice or data communications systems, the ability to effectively use back-up voice communication systems in support of reliable electric operations; and
- Demonstrate, under simulated Y2k conditions, the ability to effectively deploy elements of Y2k contingency response plans.

The September 8–9, 1999 NERC Y2k Drill Guide is posted on the NERC Y2k web site at <http://www.nerc.com/y2k>.

4.10 System Restoration and Emergency Plans

As described previously in this report, electric systems in North America are not expected interruptions of service caused by Y2k. Extensive testing completed to date indicates that Y2k does not impact the primary functions related to production and delivery of electricity.

Although the risk of electrical outages caused by Y2k appears to be minimal, the industry's defense-in-depth strategy dictates that system restoration capabilities are important. System restoration may consist of reconnecting a deenergized portion of the electric system to a portion that is energized. If there are no energized connection points, restoration would use black-start generation procedures already in place to provide initial energization. As the system is "rebuilt," parts of the system are reconnected to reestablish a fully interconnected and energized system.

Restoration strategies on the bulk electric system are driven by a specific sequence of operations designed to reenergize and reconnect the backbone transmission system as quickly as possible. These existing procedures are driven mostly by the physical constraints of the system.

The control area is the focal point for restoration procedures. NERC reliability standards require that each control area have restoration plans, including black-start capability. Dependence on external black-start resources should be coordinated to ensure they will be available under Y2k conditions. Control areas should review their system restoration plans and provide training and drills related to restoration. These drills are outside of and in addition to the NERC September 8–9 drill. The September 8–9 drill guide provides more detailed recommendations on restoration procedures, training, and drills.

4.11 Operating Interconnected

The NERC Y2k Contingency Planning Task Force and the NERC security coordinators recommend that the first priority should be to operate electrical systems of the major North American Interconnections in as close to a normal configuration as possible, with interties closed (connected). Isolated operations may be considered reasonable as a last resort under emergency conditions or pursuant to power system restoration following a blackout. It is not practical or reliable, however, to operate a normally connected system in an "islanded" configuration when it has been designed, built, and protected for interconnected operations.

4.12 Interindustry Coordination of Contingency Plans

NERC has worked closely with representatives from other critical infrastructure industries (telecommunications, natural gas, oil, and transportation) that share Y2k dependencies. An interindustry task force was formed to review

August 3, 1999

A Year 2000 Readiness Disclosure

dependency issues. The results are available in a report posted on the NERC Y2k web site at <http://www.nerc.com/y2k>.

Section 5

NERC Y2k Coordination Plan

This section provides a summary of the Y2k coordination activities of the electric industry of North America. The program is being facilitated by NERC in cooperation with the ten Regional Reliability Councils and their members. As described in Section 2 of this report, several trade associations assist NERC by facilitating efforts in various sectors of the industry: APPA, CEA, EEI, NEI, and NRECA.

The electric power industry of North America has proven its capability to meet operating challenges over the past 30 years through close coordination of planning and operations. The result is the most reliable electric service in the world.

5.1 Objectives

The goal of the NERC Y2k Coordination Plan is to prepare the electric systems of North America for reliable and sustained operations into the Year 2000 and beyond. This goal is achieved through the following objectives:

- Assuring mission-critical systems were Y2k Ready by June 30, 1999 through coordination of a rigorous program of identification, repair or replacement, and testing of software, digital components, and integrated systems. The principal tool for coordinating this effort at the industry level is the NERC Y2k Readiness Assessment Report.
- Coordinating the sharing of Y2k technical and project management information and resources. This sharing occurs through the NERC Y2k web site, industry conferences and workshops, technical committee meetings, a NERC-sponsored Y2k Coordination Task Force, an EPRI information exchange program, and other cooperative efforts.
- Coordinating the assessment of Y2k operational risks and developing and implementing contingency plans in accordance with the NERC Contingency Planning Guide.
- Coordinating industry-wide readiness drills.

5.2 Defense-in-Depth Strategy

NERC is focused on operational reliability through a “defense-in-depth” strategy. This defense-in-depth strategy assumes that although one has taken all reasonable and necessary preventive steps, there can never be 100% assurance that major system failures cannot cause a catastrophic outcome. Instead, multiple defense barriers are established to reduce the risk of catastrophic results

to extremely small probability levels and to mitigate the severity of any such events.

Despite the NERC Y2k readiness assessment process and the efforts of countless persons across the industry, there is no guarantee that all Y2k deficiencies will be identified, fixed, and tested in the remaining time. The cornerstone of the NERC Y2k plan, therefore, is to coordinate industry actions in implementing the following defense-in-depth strategy:

1. Identify and fix known Y2k problems. NERC is providing a vehicle for sharing of information on known Y2k problems and solutions associated with the operation, control, and protection of power generation, transmission, and distribution facilities. This information includes a generic inventory of Y2k susceptible components, testing guides, and Y2k project management guides.
2. Identify most probable and credible worst-case scenarios. NERC facilitated the conduct of Regional and individual system assessments of risks to determine most probable and credible worst-case scenarios. Mitigation plans for these scenarios have been developed and will be implemented on a Regional and local basis.
3. Plan for the probable — prepare for the worst. NERC is coordinating efforts to prepare for reliable and sustained operation of electric systems into the Year 2000 and beyond. Preparations include development of special operating procedures and conducting training and system-wide drills.
4. Operate systems in a precautionary posture during critical Y2k transition periods. NERC will coordinate efforts to assure electric power systems are operated in a manner commensurate with identified operating risks. Examples of precautionary measures may include reducing bulk power transfers, ensuring that all available generation and transmission facilities are in service, and increased staffing at control centers, critical substations, and generating stations during date rollover periods.

5.3 NERC Y2k Coordination Plan

To accomplish the objectives stated above, a “Y2k Coordination Plan for the Electricity Production and Delivery Systems of North America” was developed in June 1998 and is continuously maintained. This plan is divided into the following three phases:

Phase 1 (May–September 1998) — In Phase 1, NERC mobilized coordination and information sharing efforts and performed a preliminary review of Y2k readiness of electric power production and delivery systems. Phase 1 culminated in an initial report to the NERC Board of Trustees on September 14, 1998 and to DOE on September 17, 1998.

Phase 2 (September 1998–July 1999) — NERC assisted the Regional Reliability Councils and their member operating entities in resolving the known Y2k technical problems. A process of monthly reporting of progress using established criteria was completed. A Contingency Planning and Preparations Guide process was implemented to identify, assess, and prepare for most probable and credible worst-case scenarios. Phase 2 ends with this report to DOE on measures being taken to prepare bulk electric power production and delivery systems for operation during the Y2k transition.

Phase 3 (July 1999–March 2000) — During this period, NERC and its Regional Reliability Councils will review preparations and implementation of Y2k plans. NERC will facilitate the conduct of a September 8–9, 1999 drill and final arrangements to prepare for critical Y2k periods.

The NERC plan outlines the following tasks:

- Task 1. Establish an Internet web site for sharing of information on known Y2k problems and solutions. NERC has established a Y2k web site and will continue to add resources and links to other sites. The web site includes Y2k resources and an information exchange forum. (Done and continuing.)
- Task 2. Prepare a Y2k-related list of bulk electric system key contacts. This list identifies Y2k key personnel in each Region and at system operating entities. This list is maintained on the NERC Y2k web site. (Done and continuing.)
- Task 3. Establish a NERC Y2k Coordination Task Force. This Task Force has one representative from each Region who is knowledgeable about Y2k issues and the activities within the Region. The Task Force coordinates through frequent teleconferences and meetings to ensure high levels of information exchange and coordination of efforts. (Done and continuing.)
- Task 4. Coordinate assessment of Y2k readiness. NERC, along with its Regional Reliability Councils and industry partners, prepared an initial assessment of Y2k readiness and provided a report to DOE in September 1998. Quarterly reports have followed, culminating in this final report to DOE to meet the DOE request for assurances that electric systems are ready to operate into the Year 2000. (Done with follow-up reports to be provided.)
- Task 5. Develop Y2k contingency plans. NERC, in coordination with the Regional Reliability Councils, facilitated the identification of most probable and credible worst-case scenarios. These scenarios were evaluated from the perspective of probability and consequences to

determine appropriate mitigation strategies. (Contingency plans were complete as of June 30, 1999 and will be maintained for rest of year.)

- Task 6. Facilitate development and implementation of Y2k preparedness plans. NERC, in cooperation with the Regional Reliability Councils, will facilitate the development and implementation of special procedures and plans for operation during Y2k transition periods. NERC will develop the generic elements of a preparedness plan for use by operating entities in developing specific plans. (Ongoing)
- Task 7. Facilitate conduct of training and drills. Training and drills will be coordinated by Regional Reliability Councils to ensure personnel and systems are ready for operations during the Y2k transition. A successful drill on April 9, 1999 focused on communications during Y2k. A September 8–9, 1999 drill is planned as a rehearsal for the New Year's rollover. (One drill completed; second is planned.)
- Task 8. Coordination of plans to configure electric systems in precautionary posture. NERC and the Regions will coordinate the preparation of operating plans to mitigate the consequences of any adverse Y2k problems. Examples may include ensuring that all available transmission facilities are in service, starting additional generators, which include older analog controlled units, providing additional staff at control centers, power stations, and critical substations, and operating the electric system with reduced electricity transfers. The critical Y2k operating period is likely to extend several weeks before and after midnight December 31, 1999. (Ongoing)
- Task 9. Coordination of system monitoring and rapid response during Y2k period. NERC, the Regional Councils, and security coordinators will monitor conditions during Y2k-critical periods and be prepared to implement pre-established contingency plan. This includes development and implementation of a Y2k communications plan. (Communications plan is done and posted at <http://www.nerc.com>.)

Appendix A

**May 1, 1998 U.S. Department of Energy Letter
Requesting Assistance of the
North American Electric Reliability Council**



The Secretary of Energy

Washington, DC 20585

May 1, 1998

Mr. Erle Nye
Chairman of the Board
North American Electric Reliability Council
1601 Bryan Street
Dallas, TX 75201


Dear Mr. Nye:

We are writing to seek the North American Electric Reliability Council's (NERC's) assistance in assessing whether the Nation's electricity sector is adequately prepared to address the upcoming year 2000 computer problem.

The Administration is undertaking a coordinated effort to assess various sectors' readiness to address the issue. The Department of Energy (DOE) is taking the lead in working with the electricity industry to facilitate actions necessary for a smooth transition through this critical period. To this end, we are requesting that NERC undertake the coordination of an industry process to assure a smooth transition.

The electric system is such a highly interdependent network, and so vital to the security and well-being of the Nation, that there is very little margin for error or miscalculation. The Department realizes that activities designed to address this issue are already underway in many electric utilities, the Electric Power Research Institute (EPRI), and in other Federal agencies. We are concerned, however, that these activities may not be fully coordinated, or worse, may be incomplete. The Nation needs to know that a systematic process is in place to ensure that the electric supply system will not experience serious disruption.

This is truly a reliability issue, and NERC has demonstrated over the last 30 years that it is capable of coordinating the activities of electric market participants to resolve such issues. NERC is the most appropriate body to organize this process and report periodically on its status. We are confident that NERC will be able to mobilize the necessary cooperation from the Regional Reliability Councils, their members' utilities, and other industry organizations, to develop and implement a process that is both efficient and effective. We are asking that you provide us with written assurances-by July 1, 1999, that critical systems within the Nation's electric infrastructure have been tested, and that such systems will be ready to operate into the year 2000. The DOE is prepared to work with NERC to help overcome any obstacles that you might encounter in carrying out this effort. Finally, we wish to work with you to provide a suitable public forum in the late summer or early fall of

this year at which NERC and others could report on the industry's assessment of this issue and outline its plans to address this challenge.

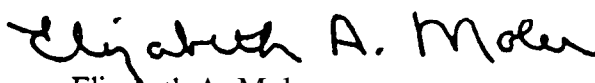
Public events on this subject are important and valuable for two reasons. First, they will convey to the public and public officials that the industry is indeed preparing systematically for the transition. Second, they will confirm to the industry that Government agencies and the public are depending on them to ensure that the transition goes smoothly.

We are looking forward to further discussions with you on this important issue.

Sincerely,

A handwritten signature in black ink, appearing to read "Federico Peña".

Federico Peña
Secretary

A handwritten signature in black ink, appearing to read "Elizabeth A. Moler".

Elizabeth A. Moler
Deputy Secretary

Appendix B

List of Organizations Y2k Ready

Or Y2k Ready with Limited Exceptions

**List of 251 Organizations Reporting to NERC
Y2k Ready (R) or Y2k Ready with Limited Exceptions (RE)**

R Adirondack Hydro Development Corporation
RE Alabama Electric Cooperative, Inc.
R Allegheny Electric Cooperative, Inc.
R Allegheny Power
R Alliant (formerly Interstate Power Company, IES Utilities Inc., Wisconsin Power & Light)
RE American Electric Power
R Ames Municipal Electric System
R Applied Energy, Inc. Naval Station Energy Facility
R Applied Energy, Inc. North Island Energy Facility
R Applied Energy, Inc. NTC/MCRD Energy Facility
RE Arizona Electric Power Cooperative, Inc.
R Arizona Public Service Company
R Arkansas Electric Cooperative Corporation
R Associated Electric Cooperative, Inc.
R ATCO Electric (formerly Alberta Power Limited)
R Austin Energy — City of Austin Electric Utility Department
R Avista Corporation (formerly Washington Water Power Company)
R Baltimore Gas and Electric Company
R Bangor Hydro Electric Company
R Basin Electric Power Cooperative
R Big Rivers Electric Corporation
R Black Hills Power and Light Company
R Board of Public Utilities Kansas City, Kansas
R Bonneville Power Administration
R Boston Edison Company
R Brazos Electric Power Cooperative, Inc.
R British Columbia Hydro and Power Authority (BC Hydro)
R Bureau of Reclamation
R Cajun Electric Power Cooperative, Inc.
RE California Department of Water Resources
R California Independent System Operator Corporation
R California Power Exchange
RE Calpine Corporation
RE Cardinal Power of Canada L.P.
RE Carolina Power & Light Company
R Cedar Falls (Iowa) Utilities
R Central and South West Services, Inc.
R Central Hudson Gas & Electric Corporation
RE Central Illinois Light Company
R Central Iowa Power Cooperative
R Central Maine Power Company
R Central Vermont Public Service Corporation

R Chelan County Public Utility District #1
R Chugach Electric Association, Inc.
R Cinergy Corp.
RE City of Anaheim (California) Public Utilities Department
RE City of Columbia, Missouri
R City of Dover, Delaware
R City of Homestead, Florida
R City of Key West, Florida (City Electric System)
RE City of Lake Worth, Florida
RE City of Pasadena, (California) Water & Power Department
RE City of Springfield, Illinois
RE City of Tallahassee, Florida
RE City of Vero Beach, Florida
R City of Springfield, Missouri
RE Colorado Springs (Colorado) Utilities
R Commonwealth Edison Company
R Commonwealth Energy System
RE Conectiv
R Consolidated Edison of New York, Inc.
R Consumers Energy
R Dairyland Power Cooperative
RE Dayton Power and Light Company
R Deseret Generation & Transmission Co-op
R DTE Energy
R Duke Energy Corporation
RE Duke Energy North America (Western Region) — CA Assets: Moss Landing,
Morro Bay, Oakland and South Bay Plants
R Duquesne Light Company
R Dynegy Power Corporation
RE East Kentucky Power Cooperative, Inc.
R East Texas Electric Cooperative, Inc.
R Eastern Utilities
R El Paso Electric Company
R Electric Energy, Inc.
RE Empire District Electric Company
R Entergy Electric System
R EPCOR (formerly Edmonton Power)
RE ERCOT ISO
RE Eugene (Oregon) Water & Electric Board
RE FirstEnergy Corporation
R Florida Municipal Power Agency
R Florida Power and Light Company
R Florida Power Corporation
RE Fort Pierce (Florida) Utilities Authority
R Gainesville (Florida) Regional Utilities
RE Golden Valley Electric Association

RE GPU Companies
RE GPU International FRCC
RE GPU International MAAC
RE GPU International NPCC
RE GPU International SERC
RE GPU International WSCC
RE Grand River Dam Authority
R Great River Energy (formerly United Power Association and Cooperative Power Association)
R Hastings (Nebraska) Utilities Department
R Hoosier Energy Rural Electric Cooperative, Inc.
R Hudson, Massachusetts Light & Power Department
RE Hydro-Québec
RE Idaho Power Company
R Illinois Power Company
R Independence (Missouri) Power and Light
R IPALCO Enterprises, Inc.
R Ipswich (Massachusetts) Municipal Utilities Department
R ISO New England Inc.
R Jacksonville (Florida) Electric Authority
R Kansas City Power & Light Company
R Kansas Electric Power Cooperative, Inc.
R KeySpan Energy Corporation
R Kissimmee (Florida) Utility Authority
R Lincoln (Nebraska) Electric System
R Lockport Cogen Facility
R Los Angeles Department of Water & Power
R Louisiana Energy and Power Authority
RE Louisville Gas & Electric Company (including Kentucky Utilities Company and Western Kentucky Energy)
R Lower Colorado River Authority
R Madison Gas and Electric Company
R Maine Public Service Company
R Manitoba Hydro
RE MAPP Coordination Center
R Maritime Electric Company, Limited
R Massachusetts Municipal Wholesale Electric Company
R Metropolitan Water District of Southern California
R Mid-America Interconnected Network Coordination Center
R MidAmerican Energy Company
RE Minnesota Power
R Minnkota Power Cooperative, Inc.
RE Montana Power Company
R Montana-Dakota Utilities Company
RE Muscatine Power and Water
R Nebraska Public Power District

RE Nevada Power Company
R New Brunswick Power Corporation
R New Century Energies (Public Service Company of Colorado & Southwestern PS)
R New England Electric System Companies
R New York Power Authority
R New York Power Pool (NY ISO)
R New York State Electric & Gas Corporation
R Niagara Mohawk Power Corporation
R Northeast Utilities System
RE Northern Indiana Public Service Company
R Northern States Power Company
R Northland Power Inc.
R Northwestern Public Service Company
R Nova Scotia Power, Inc.
R Ohio Valley Electric Corporation/Indiana-Kentucky Electric Corporation
R Oklahoma Gas and Electric Company
R Omaha Public Power District
R Ontario Hydro
R Orange and Rockland Utilities, Inc.
R Orlando (Florida) Utilities Commission
R Otter Tail Power Company
RE Owensboro (Kentucky) Municipal Utilities
R Pacific Gas & Electric Company
R Pacific Northwest Security Coordinator
R PacifiCorp
RE PECO Energy
R Pend Orielle County Public Utility District #1
R Pennsylvania Power & Light, Inc.
R PG&E Generating FRCC (formerly U.S. Generating Company)
R PG&E Generating MAAC (formerly U.S. Generating Company)
R PG&E Generating NE NPCC (formerly U.S. Generating Company)
R PG&E Generating NPCC (formerly U.S. Generating Company)
R PG&E Generating WSCC (formerly U.S. Generating Company)
RE PJM Interconnection, L. L. C.
RE Portland General Electric Company
R Potomac Electric Power Company
R Power Pool of Alberta [Alberta Power Pool] (ESBI Alberta Ltd.)
R Public Service Company of New Mexico
R Public Service Enterprise Group (Public Service Electric & Gas Company, New Jersey)
R Public Utility District No. 1 of Douglas County
R Puget Sound Energy
R Reedy Creek Improvement District
R Reliant Energy Power Generation Inc. (formerly Houston Industries Inc.)
R Reliant Energy, Inc. (formerly Houston Industries Inc.)

R Rochester Gas & Electric Corporation
RE Sacramento Municipal Utility District
RE Salt River Project
R Sam Rayburn G&T Inc.
R San Diego Gas & Electric Company
R Santee Cooper (South Carolina Public Service)
RE Saskatchewan Power Corporation
RE Seattle City (Washington) Light Department
R Seminole Electric Cooperative, Inc.
R Seneca Power Partners, L.P.
R Shrewsbury (Massachusetts) Electric Light Plant
R Sierra Pacific Power Company
R Sithe AG Energy, L.P.
R Sithe EF Kenilworth
R Sithe Energies, Inc., Oxnard Energy Facility
RE Sithe Independence Power Partners
R Sithe Medway, Framingham & Edgar LLC's
R Sithe Mystic LLC
R Sithe New Boston LLC
R Sithe Power City Partners, L.P.
R Sithe Thermo Power & Electric Inc. (Greeley Energy Facility)
R Sithe Energies Sterling Power Partners, L.P.
R Snohomish County Public Utility District #1
RE South Carolina Electric & Gas Company (SCANA)
R South Mississippi Electric Power Association
R South Texas Electric Cooperative, Inc. / Medina Electric Cooperative
R Southeastern Power Administration
R Southern California Edison Company
R Southern Company Services
R Southern Energy, Inc. – Birchwood (Sealston, Virginia)
R Southern Energy, Inc. – Canal (Sandwich, Massachusetts)
R Southern Energy, Inc. – Contra Costas (Antioch, California)
R Southern Energy, Inc. – Kendall (Cambridge, Massachusetts)
R Southern Energy, Inc. – Pittsburg (Pittsburg, California)
R Southern Energy, Inc. – Potrero (San Francisco, California)
R Southern Energy, Inc. – Stateline (Hammond, Indiana)
R Southern Illinois Power Cooperative, Inc.
R Southern Indiana Gas and Electric Company
RE Southern Minnesota Municipal Power Agency
R Southwest Power Pool
R Southwestern Power Administration
R Soyland Power Cooperative, Inc.
R St. Joseph Light & Power Company
R Sunflower Electric Power Corporation
R Tampa Electric Company
RE Taunton (Massachusetts) Municipal Lighting Plant

R Taylor Electric Cooperative, Inc.
R Tenaska Washington Partners, LP
RE Tennessee Valley Authority
RE Texas-New Mexico Power Company
R Tex-La Electric Coop. of Texas, Inc.
R TransAlta Corporation
R TransAlta Energy Corporation
R Trigen Cinergy Westwood Operating Company
R Trigen Nassau Energy Corporation
RE Tri-State Generation & Transmission Association, Inc.
R Tucson Electric Power Company
R Turlock Irrigation District
RE TXU, formerly Texas Utilities
R U.S. Army Corps of Engineers, Seattle District
RE United Illuminating Company
R Unitol Corporation, including Concord Electric, Exeter & Hampton Electric and
Fitchburg Gas and Electric
R Upper Peninsula Power Company
R UtiliCorp United, Inc. (Missouri Public Service, West Plains Energy, West
Virginia Power, Aquila Energy)
R Vermont Electric Power Company Inc.
RE Virginia Power
RE West Kootenay Power, Ltd.
RE Western Area Power Administration
R Western Farmers Electric Cooperative
R Western Resources, Inc.
R Winnipeg (Manitoba) Hydro
RE Wisconsin Electric Power Company
R Wisconsin Public Power Inc.
R Wisconsin Public Service Corporation
R Wisvest CT, LLC
R Yadkin, Inc.

Appendix C

Summary of Non-nuclear Exceptions Reports

Summary of Non-nuclear Exceptions Reports

The following non-nuclear exception items have been reported to NERC by 68 organizations. Of these 68, five do not meet the NERC Y2k Ready With Limited Exceptions Criteria. All the items in this Appendix are being tracked by NERC on a monthly basis until they are completed.

Legend:

CEMS = Continuous Emissions Monitoring System

DCS = Distributed Control System

EMS = Energy Management System

HW = Hardware

OASIS = Open Access Same-Time Information System

SCADA = Supervisory Control and Data Acquisition

SW = Software

UNK = Unknown

Organization	Facilities, Components, or Devices	Scheduled Completion Date	Justification
4516	- Communications (leased)	6/30	Pending vendor completion
1760	- SCADA	7/15	Vendor availability
8524	- Relays	7/15	Pending final testing
	- RFL9745 relays	7/15	Pending final testing
6811	- SCADA	7/23	Vendor availability
1973	- Control center computers	7/30	Vendor availability
	- Data acquisition	7/30	Vendor availability
	- Data communications	7/30	Vendor availability
9167	- SCADA	7/30	Vendor availability
4553	- DCS	7/31	Vendor availability
	- DCS	7/31	Vendor availability
	- Work/inventory management	7/18	Maintenance outage
8234	- DCS	7/31	Vendor availability
	- CEMS	7/31	Pending final testing
	- DCS	7/31	Vendor availability
	- CEMS	7/31	Pending final testing
5648	- CEMS	7/31	Pending final testing
	- CEMS	7/31	Vendor availability
3507	- CEMS	7/31	Vendor availability
	- DCS	7/31	Maintenance outage
2112	- Boiler controls	7/31	Vendor availability
	- SCADA	7/31	Pending cutover to new system
7760	- EMS	7/31	Pending cutover to new system
5997	- CEMS	7/31	Vendor availability
	- Turbine vibration	7/31	Ongoing work

	display		
2177	- Boiler feed system controls - Turbine generator	8/15 8/15	Maintenance outage Maintenance outage
8525	- CEMS	8/30	Maintenance outage
2188	- DCS	8/30	Pending final testing
3090	- Security monitoring SW - Reserve planning SW - SCADA	8/30 8/30 8/30	New system replacement New system replacement New system replacement
6744	- EMS	8/31	Vendor availability
8409	- TOC analyzer - DCS - DCS	8/31 7/31 7/31	Pending final testing Pending final testing Pending final testing
2516	- Support software - DCS - CEMS	8/31 7/31 7/31	Unknown Maintenance outage Pending final testing
1442	- Radio system	8/31	Vendor availability
1794	- Network analysis software - Application software - Data acquisition	8/31 8/31 8/	Vendor availability Pending final testing Pending final testing
5297	- SCADA	8/31	Vendor availability
1802	- Distribution center - Distribution center	8/31 8/31	Manpower constraints Manpower constraints
3178	- SCADA	8/31	Pending cutover to new system
361	- Energy scheduling and contracts - Unit commitment - OASIS - Old EMS	8/31 8/31 8/31 8/31	Vendor availability Pending final testing Vendor availability Pending decommissioning
3680	- SCADA	8/31	Vendor availability
2078	- SCADA/EMS - Generator control system	9/1 9/1	Vendor availability Vendor availability
3111	- DCS	9/1	Maintenance outage
2139	- DCS - Gas flow meter - DCS	9/1 9/1 8/1	Maintenance outage Maintenance outage Pending final testing
4003	- CEMS	9/1	Vendor availability
5161	- SCADA	9/1	Installation after summer
2015	- DCS	9/6	Maintenance outage
1388	- EMS	9/15	Cutover pending end of summer
6165	- CEMS - Master station - CEMS - LAN HW and SW	9/20 7/30 8/28 7/30	Vendor availability Vendor availability Vendor availability Work in progress
9364	- SCADA - SCADA	9/30 8/16	Vendor availability Vendor availability

	- Customer information system	8/1	New system installation
8261	- Communications systems - CEMS	9/30 9/1	Vendor availability/new installs Vendor availability
2914	- Combustion turbine	9/30	Maintenance outage
7877	- Radio System - Boiler feed pump control	9/30 9/30	Vendor availability Maintenance outage
1062	- Voice system customer center - EMS	9/30 8/31	Vendor availability Vendor availability
2462	- Customer service system	9/30	Maintenance outage
5864	- CEMS - CEMS - EMS - Customer information system - Meter program SW	9/30 9/30 9/1 9/1 8/1	Vendor availability Vendor availability Vendor availability Vendor availability Vendor availability
6921	- CEMS - SCADA - Boiler feed controls - Turbine generator controls	9/30 9/30 7/23 8/1	Vendor availability Pending final installation Vendor availability Vendor availability
2134	- Gas turbine controls	9/30	Vendor availability
4521	- SCADA - Customer information system	9/30 9/30	Manpower constraints Manpower constraints
4063	- Control center computers - Backup control center	9/30 9/30	Pending final testing Pending final testing
7615	- ISIS controls - ISIS controls - ISIS controls - ISIS controls - SVC system PC and clock - Tie line metering conversion - Capacitor bank	9/30 9/30 9/30 9/30 8/31 8/30 9/30	Vendor availability Vendor availability Vendor availability Vendor availability Vendor availability Original schedule on track Vendor availability
5816	- Governor controls - Governor controls - Governor controls	9/30 9/30 8/31	Maintenance outage Maintenance outage Vendor availability
6454	- Remote terminal unit	9/30	Vendor availability
5167	- CEMS - SCADA - Power scheduling/accounting - Billing system	9/30 8/13 8/27 7/30	Vendor availability Vendor availability Vendor availability Vendor availability

6530	- EMS/SCADA - Telephone system	10/1 9/1	Vendor availability System replacement
9671	- CEMS	10/1	Maintenance outage
7677	- Boiler controls - WAN/LAN	10/15 10/1	Vendor availability Vendor availability
2079	- Customer service system - Generator integrated test - EMS/SCADA	10/15 9/30 9/30	Vendor availability Maintenance outage Vendor availability
1572	- Generator integrated test - Generator integrated test - Microwave alarm system - CEMS	10/31 9/30 9/1 8/1	Maintenance outage Maintenance outage Vendor availability Vendor availability
6425	- SCADA	10/31	Vendor availability
1781	- DCS - DCS - DCS	10/15 10/15 12/15	Maintenance outage Maintenance outage Maintenance outage
6530	- CEMS	10/31	Vendor availability
5796	- DCS - DEH programmer - DCS - Scan 3000 - DCS - DEH programmer - CEMS - DCS	10/31 8/1 10/31 8/1 10/31 8/1 11/1 10/31	Vendor availability Vendor availability Vendor availability Vendor availability Vendor availability Vendor availability Maintenance outage Vendor availability
5540	- Controller - Controller	11/1 11/1	Vendor availability Vendor availability
1142	- DCS - CEMS - CEMS	11/13 9/30 10/31	Maintenance outage Vendor availability Vendor availability
7199	- DCS - Mobile radio - ACD switch - CEMS	11/18 11/1 10/15 11/15	Maintenance outage Vendor availability On hold pending merger solution Vendor availability
1765	- Controller - EMS	11/19 8/31	Vendor availability Vendor availability
1146	- Data acquisition - Data acquisition - EMS/SCADA	11/30 10/31 10/31	Maintenance outage Maintenance outage Vendor availability
7339	- CEMS - CEMS - CEMS - CEMS - CEMS	11/30 11/30 11/30 11/30 11/30	Pending regulatory requirements Pending regulatory requirements Pending regulatory requirements Pending regulatory requirements

			requirements Pending regulatory requirements Pending regulatory requirements
6538	<ul style="list-style-type: none"> - Coal handling controls - DCS - Combustion controls - Scubber controls - Burner controls 	11/30 8/31 7/15 8/31 8/31	Vendor availability Vendor availability Vendor availability Maintenance outage Maintenance outage
3364	- DCS	11/30	Vendor availability
1514	<ul style="list-style-type: none"> - TSIE PROM upgrade - Precipitator controls 	12/1 10/1	Maintenance outage Maintenance outage

Appendix D

American Public Power Association

Summary Data



Breakdown: Year 2000 Survey Results

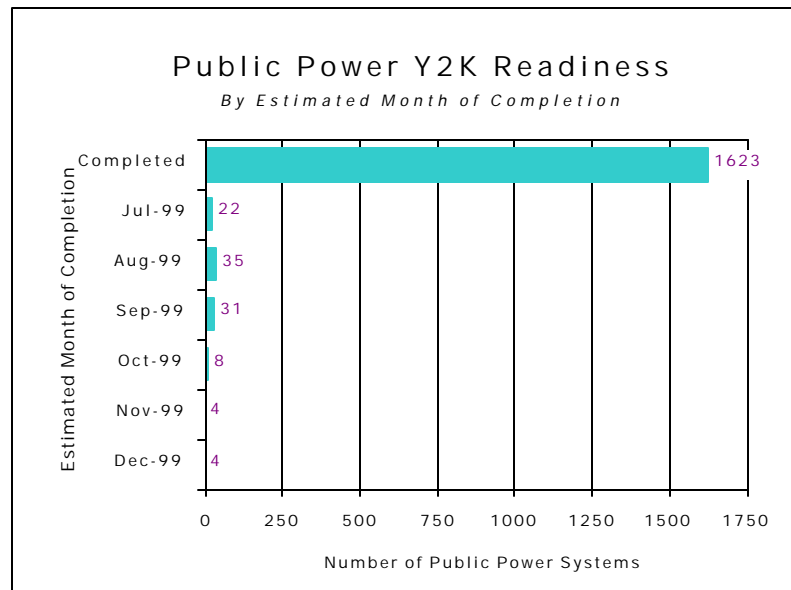
August 3, 1999

Survey Response

- In 1998, a total of **2,012 surveys** was sent to 240 large, 538 middle, and 1,234 small public power systems. Here “large” means public power utilities with more than 15,000 customer meters, plus major wholesale utilities; “middle” means systems with 3,000 to 15,000 customers, plus mid-sized wholesale utilities; and “small” means utilities with less than 3,000 customers.
- In March 1999, APPA re-surveyed the middle (538) and largest (240) public power systems. The **overall response** to this second survey was 91.9% (715 systems). In June 1999, APPA re-surveyed all systems. The **overall response** to this latest survey was 86.3% (1,737 systems).
- Combining the three surveys, the **overall response** was 98.86% of utilities (1,989), representing 18,166,981 meters or 99.95% of the approximately 18,175,205 ultimate metered customers of public power.*
- The **response** to the large surveys was 100% (240), representing 13,312,296 meters or 73.24% of public power; to the middle surveys, 100% (538), representing 3,466,831 meters or 19.07% of public power; and to the small surveys, 98.14% (1,211), representing 1,387,854 meters or 7.64% of public power.

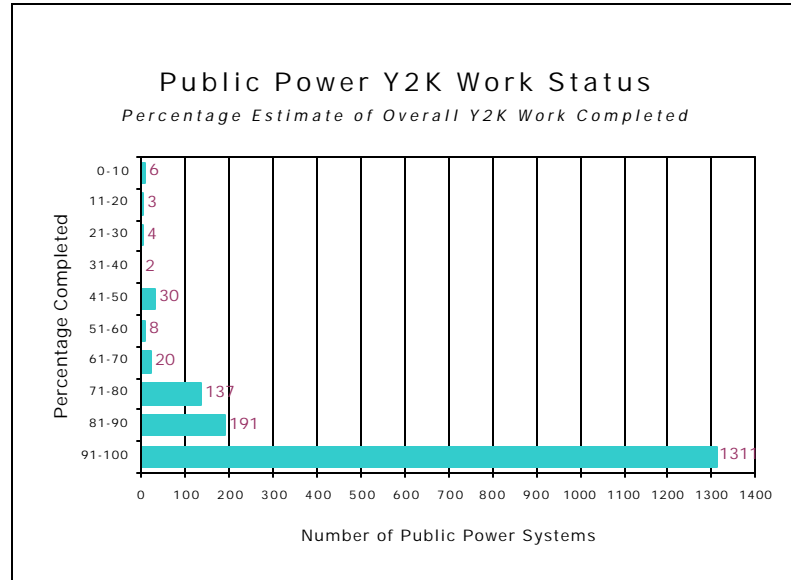
Readiness Estimates—From June 1999 Survey

- For the 1,737 respondents estimating when they would be **Y2K ready for mission-critical systems**, 1,623 declared they would be “Y2K Ready” by June 30, 1999, and over 98% will be “Y2K Ready” by the end of the Third Quarter, 1999. The chart below shows public power system Y2K

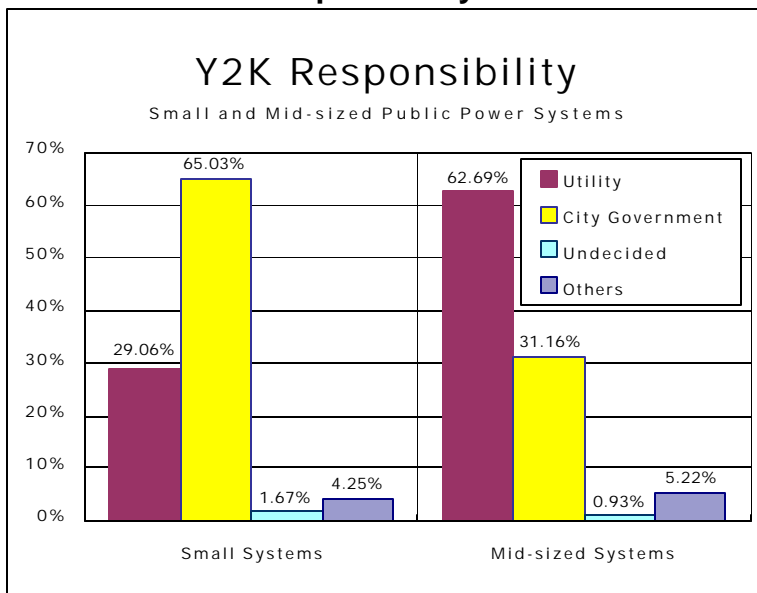


readiness by **estimated month of completion**.

- 1,712 respondents estimated their **percentage of citywide Y2K readiness work completed**. The average work completed is 95.18%. The chart below provides more detail.



Responsibility—Small and Middle Systems



- 29.06% of the small and 62.69% of the middle systems stated the **utility** was responsible for dealing with Y2K problems. 65.03% of the small and 31.16% of the middle stated the **city government** was responsible.

- 1.67% of the small and 0.93% of the middle were **undecided** who was responsible.

- 4.25% of small and 5.22% of middle systems stated **others** were responsible. “Others” ranged from city

clerks to contracting companies.

- For the large systems, the **utility** was responsible for dealing with Y2K electricity matters.

Information and Planning—All

- 84.29% of all utilities say they already have **enough information** on the Y2K problem.
- 93.84% of the small have considered the impact on **informational and billing systems**; 82.45% of the small, the impact on **operational and embedded systems**; and 87.10% of the small have initiated **action** to pursue solutions.
- 100% of all systems have a **planning document**, provided by APPA. 92.72% of middle and 98.33% of large systems reported having an additional **written or unwritten plan** addressing the problem.
- For those middle and large systems responding to the **March 1999 survey**, their planning documents addressed the following areas, when applicable:

	<u>Middle</u>	<u>Large</u>
Generation Operations	90.18%	96.90%
EMS / SCADA	93.29%	99.44%
Telecommunications	90.66%	97.80%
Transmission Operations	88.81%	96.82%
Distribution Operations	99.18%	98.39%
Business Systems	97.62%	98.48%
Building/Utility Security	91.11%	93.92%

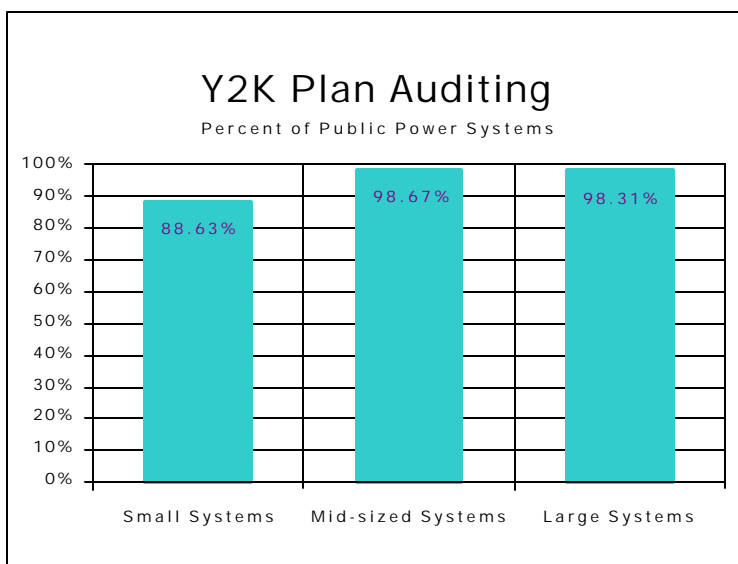
Testing and Results—From March 1999 Survey

- Speaking only of mission-critical systems, 73.08% of the middle and 82.76% of the large groups have completed **some testing**.
- For respondents completing some testing, **results** of the testing are as follows:

	<u>Middle</u>	<u>Large</u>
Zero impact on electric delivery systems	66.86%	47.90%
Minor impact on electric delivery systems	32.00%	52.10%
Major impact on electric delivery systems	0.57%	0.0%
100% failure of electric delivery systems	0.57%	0.0%

Contingency Planning

- Of the systems surveyed in June 1999, 91.81% of the middle and 96.20% of the large systems have **Y2K specific contingency plans** to maintain continuous operations.
- Although the North American Electric Reliability Council's September 8/9, 1999, Y2K planning drill is geared for the bulk electric systems in the U.S., 28.21% of the middle and 47.2% of the large public power systems **plan to participate** in the NERC Y2K drill.



- The U.S. Department of Energy in early 1999 asked whether electric utilities in the U.S. are performing an internal or external audit/review of their Y2K Programs. APPA's June 1999 data indicate that 92.98% of all public power systems are **performing Y2K program reviews**. The chart at the left provides further information.

Further Information

- For additional information, contact Michael J. Hyland, APPA's director of engineering services, by phone at 202-467-2986 or by e-mail at mhyland@APPAnet.org.

Source: U.S. Department of Energy, Energy Information Administration Form EIA-861, 1996 data.

Appendix E

National Rural Electric Cooperative Association

Summary Data

NRECA

Y2K Readiness Snapshot - June 1999

(excerpted from survey conducted by NRECA on behalf of NERC, June 1999)

Data reflect number of co-ops reporting each response unless otherwise noted

General Information

Number of distribution systems responding to survey 821

(One co-op reported too late for inclusion in data set)

Number of meters served by survey respondents 13,439,314

	<u>Yes</u>	<u>In Process</u>	<u>Unwritten</u>	<u>No</u>
Have written plan for Y2K readiness?	595	98	84	40

	<u>Yes</u>	<u>No</u>
If no, does co-op intend to prepare one?	1	38

(This question only involves those who answered 'no' to the written plan question above.)

	<u>Min</u>	<u>Max</u>
When?	NA	NA

(This question only involves those who answered 'yes' to the question about intent to prepare a written plan above.)

	<u>Yes</u>	<u>No</u>
Board receives regular reports?	788	26

Status

	<u>Avg.</u> <u>% Complete</u>	<u>Min</u>	<u>Est. Complete Date</u> <u>Max</u>	<u>Avg.</u>
Inventory	99	Jan-97	Dec-99	Feb-99
Assessment	98	Jan-98	Dec-99	Mar-99
Testing	91	Apr-98	Dec-99	Jun-99

	<u>Yes</u>	<u>No</u>
Does Y2K analysis take into account supply chain breakdown?	732	79

Status of contingency preparedness

	<u>Haven't</u> <u>Started</u>	<u>Started</u>	<u>Have a Plan</u>	<u>Tested</u> <u>and</u> <u>drilled</u> <u>plan</u>	<u>NA</u>
Special operating procedures/plans	13	183	509	100	5
Personnel staff/training	15	181	505	98	7

	<u>Min</u>	<u>Max</u>	<u>Avg</u>
When does co-op expect to be Y2K ready?	Oct-98	Dec-99	Jun-99

Testing-Vendor Certification Information (see below for equipment lists)

.

	<u>Number of equipment/ applications reported</u>	<u>Using integrated testing?</u>	<u>Using component testing?</u>	<u>Using Simu- lations?</u>	<u>Using outside testing?</u>	<u>Using Vendor verific.?</u>
EMS/SCADA	1107	164	151	129	71	221
Telecommunications	1856	201	179	148	101	284
Substation, Controls, Systems Protection and Distribution						
Internal to substations	1309	213	190	150	99	283
External to substations	986					

(Table reflects the number of equip./appl. reported by co-ops and the number of co-ops using each type of testing, by equip./appl. category.

Each co-op can have more than one item in each category of equip./appl.)

(Several testing strategies are being used in each category of equipment.)

Contingency planning completed for equipment categories?

(see below for equipment lists)

EMS/SCADA	
Telecommunications	169
Substation, Controls, Systems Protection and Distribution	213
	224

(Table reflects number of co-ops reporting contingency planning completed for each category.)

Equipment/Applications Surveyed:

EMS/SCADA

Control center computer systems

Data acquisition subsystems

UPS systems/Emergency generator

Voice and data communications systems

Remote terminal units (RTUs)

Metering equipment systems (tie lines)

Backup control center

Telecommunications

Telephone switches and key systems

Microwave systems

Mobile radio

SCADA radio

Data WAN/LANs including networking equipment

Modems

Network equipment

Substation, Controls, Systems Protection and Distribution

Transmission and/or distribution facilities internal to substations

Microprocessor relays?

Special protection schemes (gen. rejectn., line trip., etc.)

Load shedding controls and underfrequency relays

Circuit breaker and switching device controls

LTC and regulator controls

Recloser controls - inside the substation

Digital fault recorders/digital transient recorders?

Terminal equipment for telecommunications facilities

Substation service controls (incl. battery chargers)

Disturbance analyzers

Distribution facilities outside the substation

Transfer/recloser controls - outside the substation

Sectionalizer controls - outside the substation

Capacitor controls - outside the substation

Voltage regulators - outside the

Fiber systems

substation

Data gathering equipment - outside the substation

Leased lines

Power line carrier systems

Satellite systems

Telecommunications management systems

Y2K Readiness Snapshot - June 1999

Existence and Readiness of Equipment/Applications By Category

Y2K Phases for Mission Critical Equipment

	<u>Have item?*</u>	<u>Inventory</u>	<u>Avg. % of work complete Assessment</u>	<u>Testing/ Remediation</u>
EMS/SCADA				
Control center computer systems?	166	100	100	92
Data acquisition subsystems?	160	100	99	93
UPS systems/Emergency generator?	204	100	100	98
Voice/data communications systems?	230	100	98	95
Remote terminal units (RTUs)?	162	100	99	96
Metering equipment systems (tie lines)?	129	100	99	94
Backup control center?	56	100	100	97
Telecommunications				
Telephone switches and key systems?	272	100	99	95
Microwave systems?	79	99	99	97
Mobile radio?	298	99	98	96
SCADA radio?	124	99	99	97
Data WAN/LAN?	210	100	99	94
Modems?	279	99	99	96
Network equipment?	224	100	99	96
Fiber?	61	99	97	94
Leased lines?	144	99	97	94
Power line carrier?	91	99	99	97
Satellite?	19	97	93	97
Telecom management systems?	55	99	99	97

***Number of co-ops reporting item requested.*

Y2K Phases for Mission Critical Equipment, Continued

Substation, Controls, Systems Protection and Distribution

	<u>Have item?*</u>	<u>Inventory</u>	<u>Avg. % of work complete</u>	
			<u>Assessment</u>	<u>Testing/ Remediation</u>
Transmission and/or distribution facilities internal to substations				
Microprocessor relays	132	99	99	94
Special protection schemes (line trip., etc.)	81	99	98	96
Load shedding controls and underfrequency relays	74	98	98	96
Circuit breaker and switching device controls	198	99	99	96
LTC/Regulator	217	99	99	95
Recloser controls - inside substation	259	100	99	95
Digital fault recorders/digital transient recorders	60	99	97	91
Terminal equipment for telecommunications facilities	84	99	99	94
Substation Service Controls	165	99	99	95
Disturbance analyzers	39	99	99	94
Distribution facilities outside the substation				
Transfer/recloser controls?	223	99	98	95
Sectionalizer controls?	148	99	98	95
Capacitor controls?	189	99	98	94
Voltage regulators?	273	99	98	94
Data gathering equipment?	153	100	99	93

***Number of co-ops reporting item requested.*

% projected readiness of equip./appl. types by quarter

	<u>1q99</u>	<u>2q99</u>	<u>3q99</u>	<u>4q99</u>
EMS/SCADA	84	93	99	100
Telecommunications	88	96	100	100
Substation, Controls, Systems Protection and Distribution	87	96	100	100

Appendix F

List of Bulk Electric Organizations

Completing Y2k Contingency Plans

In Accordance with NERC Guidelines

Appendix F
Bulk Electric Entities in North America
Completing NERC Y2k Contingency Plans

Operating as:

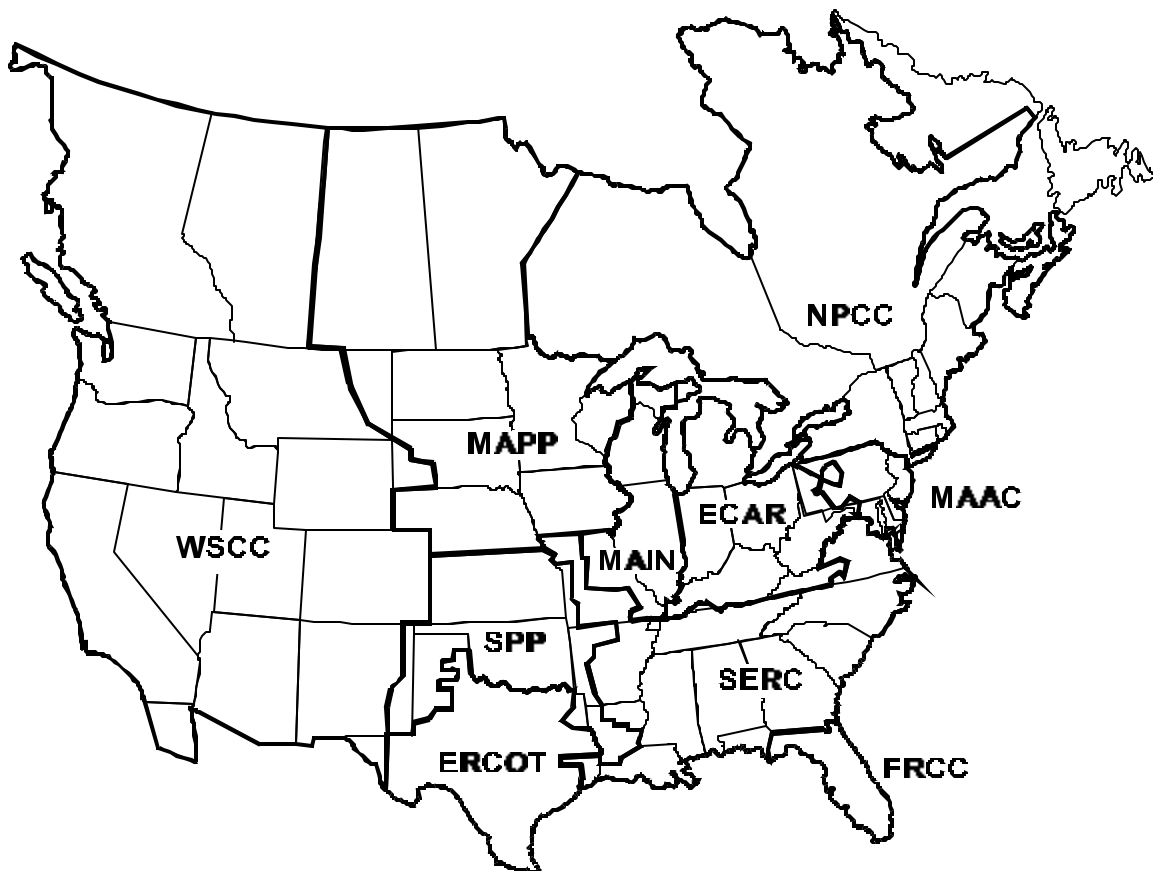
CA = Control Area

TP = Transmission Provider

SC = Security Coordinator

- ✓ Indicates completed Y2k contingency plans in accordance with NERC Y2k Contingency Planning Guide.

Map of NERC Regions



CA	TP	SC	Bulk Electric Organization	Region
1	1	✓	Alabama Electric Cooperative, Inc.	SERC
1	1	1 ✓	Allegheny Power	ECAR
1	1	✓	Alliant Energy East (formerly IEC)	MAIN
1	1	✓	Alliant Energy West (formerly IEC)	MAPP
1	1	✓	Ameren Corporation	MAIN
1	1	1 ✓	American Electric Power	ECAR
1	1	✓	Arizona Public Service Company	WSCC
1	1	✓	Associated Electric Cooperative, Inc.	SERC
	1	✓	ATCO Electric (formerly Alberta Power Limited)	WSSC
1	1	✓	Austin Energy — City of Austin Electric Utility Department	ERCOT
1	1	✓	Avista Corporation (formerly Washington Water Power)	WSCC
	1	✓	Baltimore Gas & Electric Company	MAAC
	1	✓	Bangor Hydro Electric Company	NPCC
	1	✓	Basin Electric Power Cooperative	MAPP
	1	✓	Basin Electric Power Cooperative	WSCC
1	1	✓	Big Rivers Electric Corporation	ECAR
	1	✓	Black Hills Power and Light Company	WSCC
1	1	✓	Board of Public Utilities Kansas City, Kansas	SPP
1	1	✓	Bonneville Power Administration	WSCC
	1	✓	Boston Edison Company	NPCC
1	1	✓	Brazos Electric Power Cooperative, Inc.	ERCOT
1	1	✓	British Columbia Hydro & Power Authority (BC Hydro)	WSCC
	1	✓	Bureau of Reclamation	WSCC
1	1	✓	Cajun Electric Power Cooperative, Inc.	SERC
	1	✓	California Department of Water Resources	WSCC
1		1 ✓	California Independent System Operator Corporation	WSCC
2	1	✓	Carolina Power & Light Company	SERC
1	1	✓	Central and South West Corporation, Inc.	ERCOT
1	1	✓	Central and South West Corporation, Inc.	SPP
	1	✓	Central Hudson Gas & Electric Company	NPCC
1	1	✓	Central Illinois Light Company	MAIN
	1	✓	Central Iowa Power Cooperative	MAPP
1	1	✓	Central Louisiana Electric Company	SPP
	1	✓	Central Maine Power Company	NPCC
	1	✓	Central Vermont Public Service Corporation	NPCC
1	1	✓	Chelan County Public Utility District	WSCC
1	1	✓	Cinergy Corporation	ECAR
1	1	✓	City of Columbia, Missouri	MAIN
1	1	✓	City of Homestead, Florida	FRCC
1	1	✓	City of Independence, Missouri Power and Light	SPP
	1	✓	City of Key West, Florida (City Electric System)	FRCC

1	1	✓	City of Lake Worth, Florida	FRCC
1	1	✓	City of New Smyrna Beach, Florida	FRCC
1	1	✓	City of Pasadena, (California) Water & Power Department	WSCC
1	1	✓	City of Springfield, Illinois — City Water, Light & Power	MAIN
1	1	✓	City of Tallahassee, Florida	FRCC
	1	✓	City Public Service — San Antonio, Texas	ERCOT
	1	✓	City Utilities of Springfield, Missouri	SPP
	1	✓	City of Vero Beach, Florida	FRCC
	1	✓	Colorado Springs (Colorado) Utilities	WSCC
1	1	✓	Comision Federal de Electricidad	WSCC
1	1	✓	Commonwealth Edison Company	MAIN
	1	✓	Commonwealth Energy System	NPCC
	1	✓	Conectiv	MAAC
	1	✓	Consolidated Edison of New York, Inc.	NPCC
	1	✓	Consumers Energy	ECAR
1	1	✓	Dairyland Power Cooperative	MAPP
1	1	✓	Dayton Power and Light Company	ECAR
	1	✓	Deseret Generation & Transmission Cooperative	WSCC
	1	✓	DTE Energy	ECAR
1	1	1	Duke Energy Corporation	SERC
1	1	✓	Duquesne Light Company	ECAR
1	1	✓	East Kentucky Power Cooperative, Inc.	ECAR
	1	✓	Eastern Utilities	NPCC
1	1	✓	El Paso Electric Company	WSCC
1	1	✓	Electric Energy, Inc.	MAIN
1	1	✓	Empire District Electric Company	SPP
1		✓	ENRON SE Corp. — Brownsville	SERC
1		✓	ENRON SE Corp. — New Albany	SERC
1		✓	ENRON SE Corporation — Caledonia	SERC
1	1	1	Entergy Electric System	SERC
		1	ERCOT ISO	ERCOT
	1	✓	Eugene (Oregon) Water & Electric Board	WSCC
1	1	✓	FirstEnergy Corporation	ECAR
1		✓	Florida Municipal Power Pool	FRCC
1	1	1	Florida Power and Light Company	FRCC
1	1	✓	Florida Power Corporation	FRCC
	1	✓	Ft. Pierce (Florida) Utilities Authority	FRCC
1	1	✓	Gainesville (Florida) Regional Utilities	FRCC
	1	✓	Georgia System Operations Corp. (Oglethorpe Power)	SERC
	1	✓	GPU Companies	MAAC
1	1	✓	Grand River Dam Authority	SPP
1	1	✓	Great River Energy	MAPP

1	1	✓	Hoosier Energy Rural Electric Cooperative, Inc.	ECAR
1	1	1 ✓	Hydro-Québec	NPCC
1	1	✓	Idaho Power Company	WSCC
1	1	✓	Illinois Power Company	MAIN
1	1	✓	Imperial Irrigation District	WSCC
1	1	✓	IPALCO Enterprises, Inc.	ECAR
1		1 ✓	ISO New England Inc.	NPCC
1	1	✓	Jacksonville (Florida) Electric Authority	FRCC
1	1	✓	Kansas City Power & Light Company	SPP
	1	✓	Keyspan Energy Corporation	NPCC
	1	✓	Kissimmee (Florida) Utility Authority	FRCC
1		✓	Lafayette Utilities System	SPP
	1	✓	Lakeland Electric, City of Lakeland, Florida	FRCC
1	1	✓	Lincoln (Nebraska) Electric System	MAPP
1	1	✓	Los Angeles Department of Water & Power	WSCC
1	1	✓	Louisiana Energy and Power Authority (LEPA)	SPP
1	1	✓	Louisville Gas & Electric Utility Company, Kentucky Utilities Company, and Western Kentucky Energy	ECAR
1	1	✓	Lower Colorado River Authority	ERCOT
1	1	✓	Madison Gas and Electric Company	MAIN
		1 ✓	MAIN Security Coordinator	MAIN
	1	✓	Maine Public Service Company	NPCC
1	1	✓	Manitoba Hydro	MAPP
		1 ✓	MAPP Security Coordinator	MAPP
	1	✓	Maritime Electric Company, Limited	NPCC
1		1 ✓	MECS (CA for Detroit Edison and Consumers Energy)	ECAR
1	1	✓	MidAmerican Energy Company	MAPP
1	1	✓	Minnesota Power	MAPP
	1	✓	Minnkota Power Cooperative, Inc.	MAPP
1	1	✓	Montana Power Company	WSCC
	1	✓	Montana-Dakota Utilities Company	MAPP
1	1	✓	Muscatine Power and Water	MAPP
1	1	✓	Nebraska Public Power District	MAPP
1	1	✓	Nevada Power Company	WSCC
1	1	✓	New Brunswick Power Corporation	NPCC
1	1	✓	New Century Energies	SPP
1	1	✓	New Century Energies	WSCC
	1	✓	New England Electric Systems Companies	NPCC
	1	✓	New York Power Authority	NPCC
1		1 ✓	New York Power Pool (NY ISO)	NPCC
	1	✓	New York State Electric & Gas Corporation	NPCC
	1	✓	Niagara Mohawk Power Corporation	NPCC
	1	✓	Northeast Utilities System	NPCC

1	1	✓	Northern Indiana Public Service Company	ECAR
1	1	✓	Northern States Power Company	MAPP
	1	✓	Nova Scotia Power, Inc.	NPCC
1	1	✓	Ohio Valley Electric/Indiana-Kentucky Electric Corporation	ECAR
1	1	✓	Oklahoma Gas and Electric Company	SPP
1	1	✓	Omaha Public Power District	MAPP
1	1	1	✓ Ontario Hydro	NPCC
	1	✓	Orange & Rockland Utilities, Inc.	NPCC
	1	✓	Orlando (Florida) Utilities Commission	FRCC
1	1	✓	Otter Tail Power Company	MAPP
	1	✓	Pacific Gas & Electric Company	WSCC
		1	✓ Pacific Northwest Security Coordinator	WSCC
2	1	✓	PacifiCorp	WSCC
	1	✓	PECO Energy	MAAC
	1	✓	Pennsylvania Power & Light, Inc.	MAAC
1		1	✓ PJM Interconnection, L.L.C.	MAAC
	1	✓	Platte River Power Authority	WSCC
1	1	✓	Portland General Electric Company	WSCC
	1	✓	Potomac Electric Power Company	MAAC
1		✓	Power Pool of Alberta (ESBI Alberta Ltd., control area)	WSCC
	1	✓	Power Pool of Alberta (System operator, no control area)	WSCC
1	1	✓	Public Service Company of New Mexico	WSCC
	1	✓	Public Service Enterprise Group (Public Service Electric & Gas Company, New Jersey)	MAAC
1	1	✓	Public Utilities Board of the City of Brownsville	ERCOT
1	1	✓	Public Utility District No. 1 of Douglas County	WSCC
1	1	✓	Public Utility District No. 2 of Grant County	WSCC
1	1	✓	Puget Sound Energy	WSCC
1		✓	Reedy Creek Improvement District	FRCC
1	1	✓	Reliant Energy, Inc. (formerly Houston Industries)	ERCOT
	1	✓	Rochester Gas & Electric Corporation	NPCC
	1	✓	Sacramento Municipal Utility District	WSCC
1	1	✓	Salt River Project	WSCC
	1	✓	San Diego Gas & Electric	WSCC
1	1	✓	Santee Cooper (South Carolina Public Service)	SERC
1	1	✓	Saskatchewan Power Corporation	MAPP
1	1	✓	Seattle City (Washington) Light Department	WSCC
1	1	✓	Seminole Electric Cooperative, Inc.	FRCC
1	1	✓	Sierra Pacific Power Company	WSCC
1	1	✓	South Carolina Electric & Gas Company	SERC
1	1	✓	South Texas Electric Cooperative, Inc.	ERCOT
3	1	✓	Southeastern Power Administration	SERC
	1	✓	Southern California Edison Company	WSCC

1	1	1	✓	Southern Company Services (including Dalton, MEAG, Oglethorpe)	SERC
1	1		✓	Southern Illinois Power Cooperative, Inc.	MAIN
1	1		✓	Southern Indiana Gas and Electric Company	ECAR
1	1		✓	Southern Minnesota Municipal Power Agency	MAPP
1	1		✓	Southern Mississippi Electric Power Association	SERC
		1	✓	Southwest Power Pool	SPP
1	1		✓	Southwestern Power Administration	SPP
1	1		✓	St. Joseph Light & Power Co.	MAPP
1	1		✓	Sunflower Electric Power Corporation	SPP
1	1		✓	Tacoma Public Utilities	WSCC
1	1		✓	Tampa Electric Company	FRCC
1	1	1	✓	Tennessee Valley Authority	SERC
1	1		✓	Texas Utilities	ERCOT
1	1		✓	Texas-New Mexico Power Company	ERCOT
		1	✓	Transalta Corporation	WSCC
1	1		✓	Tucson Electric Power Company	WSCC
		1	✓	Turlock Irrigation District	WSCC
		1	✓	United Illuminating Company	NPCC
1	1		✓	Upper Peninsula Power Company	MAIN
2	1		✓	UtiliCorp United, Inc. (Missouri PS & WestPlains Energy)	SPP
		1	✓	Vermont Electric Power Company, Inc.	NPCC
1	1	1	✓	Virginia Power	SERC
		1	✓	West Kootenay Power Ltd.	WSCC
1	1		✓	Western Area Power Administration	MAPP
3	1	1	✓	Western Area Power Administration	WSCC
1	1		✓	Western Farmers Electric Cooperative	SPP
1	1		✓	Western Resources, Inc.	SPP
		1	✓	Winnipeg (Manitoba) Hydro	MAPP
1	1		✓	Wisconsin Electric Power Company	MAIN
1	1		✓	Wisconsin Public Service Corporation	MAIN
1	1		✓	Yadkin, Inc.	SERC
